

GAS ROYALTY CALCULATION 2015 – AN UPDATE

By

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**33RD ANNUAL ADVANCED
OIL, GAS & ENERGY RESOURCES LAW COURSE
October 1-2, 2015**

CHAPTER 18

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Biography

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Mr. Pearson earned his B.A., with high honors, from The University of Texas at Austin in 1975 and his J.D. from The University of Texas School of Law in 1978, where he was an Associate Editor of *The Texas Law Review*.

Memberships

Mr. Pearson is a member of the State Bar of Texas, the Houston Bar Association, the International Bar Association, and the American Bar Association. Mr. Pearson is a Past Chair of the Council of the Oil, Gas and Energy Resources Law Section of the State Bar of Texas.

Awards

Mr. Pearson has been listed in *The Best Lawyers in America* under Natural Resources Law and Oil & Gas Law since 2004 and has been named a "Texas Super Lawyer" by Thomson Reuters since 2007. Mr. Pearson has also been listed in "Who's Who in Energy" by The Houston Business Journal since 2012 and was listed by Legal Media Group among the "World's Leading Energy & Natural Resources Lawyers" in 2008, 2010, and 2013. In 2005, *Lawdragon Magazine* selected Mr. Pearson as one of the "500 Best Lawyers in America", in 2007 as one of the "500 Top Deal Makers in America", and in 2010 as one of the "Lawdragon Top 3000."

Publication & Speaking Engagements

Mr. Pearson has authored a number of articles relating to finance and oil and gas matters and has also been a frequent speaker at continuing legal education programs and seminars. Most recently, Mr. Pearson delivered a paper entitled "Selected Drafting Issues in Midstream Contracts" at the 2015 Gas and Power Institute sponsored by The University of Texas School of Law, the Oil, Gas and Energy Resources Law Section of the State Bar of Texas, and the Energy Bar Association, and a paper entitled "A Primer on Production Payments" at the 2010 State Bar of Texas Advanced Oil, Gas and Energy Resources Law Course.

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I. Introduction

We would all agree, I think, that oil and gas producers and royalty owners share at least one clear, common objective – the accumulation of wealth from hydrocarbon production. Nevertheless, because their's is not a relationship of equals – oil and gas producers ordinarily possess superior technical expertise and financial resources and control the performance of operations and, in most cases, the marketing of hydrocarbons and the distribution of revenues – royalty owners and oil and gas producers have found themselves, since the Lucas Gusher on Spindletop Hill south of Beaumont, Texas, ushered in the modern oil and gas industry on January 10, 1901¹, in the roles of wary, natural adversaries who “live in the same house”, much like hyper-competitive siblings, old cats and young dogs, and Longhorns and Aggies. They must, out of necessity, coexist and, from time to time, even cooperate. They remain, however, ever vigilant to assure that one does not gain an advantage over the other. In the case of the royalty owner, that means making certain that he receives everything from the producer to which he is entitled (and maybe a little more). In the case of the oil and gas producer, that means making certain that the royalty owner receives that to which he is entitled, but no more, with any doubts being resolved in the producer's favor.

Against this backdrop, it is no surprise that, in my (now) thirty-seven years in practice, few oil and gas issues have generated more complex and challenging litigation, or more erudite, impassioned, or (occasionally) entertaining commentary, than the subject of gas royalty calculation. Driven largely by the revolution in the regulatory and commercial structures of U.S. natural gas marketing over the last forty-five years, and, of course, the significant amounts of money almost always in controversy, oil and gas

producers and royalty owners have continued to battle in the Texas courts –with unwavering determination and creativity, and in most cases, with mutual respect and civility – over a wide range of royalty-related issues, including, *inter alia*, the meanings of “market value”, “amount realized”, “gross proceeds”, “net proceeds”, “at the well”, and “at the point of sale”, the scope of the producer's duties under the implied covenant to market, the responsibility for post-production costs, and the character and effect of division orders, among many others. In many cases, the Texas courts have resolved the disputes in ways that enhanced our understanding of the principles of royalty calculation and provided logical roadmaps for future conduct. In other cases, unfortunately, the courts have raised more questions than they have answered and generally have left us scratching our heads in confusion.

Much excellent commentary regarding gas royalty calculation has been published over the years.² Indeed, this author first

² E.g., Dick Watt, *Analysis of Royalty Clauses and Issues – Past, Present and in the Future*, 41ST ANN. OIL, GAS & MIN. L. INST., Univ. of Texas School of Law, St. Bar OGERL Section, Paper 6 (2015) (hereinafter, “Watt”); Robert L. Theriot and Joshua P. Downer, *Royalty and Deductions – Old Issues in New Plays*, 39 OIL, GAS & ENERGY RES. L. SECTION REPORT, No. 1, St. Bar of Texas, at 131 (2014) (hereinafter “Theriot and Downer”); Stuart C. Hollimon, *Current Issues in Royalty Calculation*, 31ST ANN. ADV. OIL, GAS & ENERGY RES. L. COURSE, St. Bar of Texas, Ch. 18 (2013); Guy Stanford Lipe and Rebecca Lynn Phillips, *Current Developments and Trends in Royalty Litigation*, 64TH ANN. INST. ON OIL & GAS LAW § 5.01 (2013) (hereinafter, “Lipe and Phillips”); Carl E. Glaze and Kelly Laukhof, *Brief Primer and Recent Texas Cases Re Oil and Gas Lease Royalty*, 30TH ANN. ADV. OIL, GAS & ENERGY RES. L. COURSE, St. Bar of Texas, Ch. 7 (2012); Clay Person, *Check It Out – Reviewing the Royalty Check after Shell v. Ross*, 30TH ANN. ADV. OIL, GAS & ENERGY RES. L. COURSE, St. Bar of Texas, Ch. 4 (2012); Mark G. Rodriguez & Rebecca L. Phillips, *Royalty and Post-Production Costs: Differences Across the Producing States*, 36 OIL, GAS & ENERGY RES. L. SECTION REPORT, No. 4, St. Bar of Texas, at 13 (2012) (hereinafter, “Rodriguez and Phillips”); Stuart C. Hollimon, *Revisiting the Gas Royalty Clause for the 21st Century*, 34TH ANN. OIL, GAS & MIN. L. INST., Univ. of Texas School of Law, St. Bar OGERL Section,

¹ *Spindletop*, Wikipedia, <http://www.wikipedia.org/?title=Spindletop>.

Paper 9 (2008); Mark C. Rodriguez and Walter R. Mayer, *Royalty and Post-Production Costs: Keeping Track of It All*, 25th ADV. OIL, GAS & ENERGY RES. L. COURSE, St. Bar of Texas, Ch. 7 (2007) (hereinafter, "Rodriguez and Mayer"); David E. Pierce, *Developments in Non-Regulatory Oil and Gas Law: Beyond Theories and Rules to the Motivating Jurisprudence*, 58th ANN. INST. ON OIL & GAS LAW § 1.04 (2007); Jeffrey C. King, *The Compression of Natural Gas – Is It Production or Post-Production? Is It Deductible from Royalties? If So, How Much?*, 24th ANN. ADV. OIL, GAS & ENERGY RES. L. COURSE, St. Bar of Texas, Ch. 8 (2006); Peter E. Hosey, "*Follow the Money!*" *Oil and Gas Leases and Divisions Orders*, 23rd ANN. ADV. OIL, GAS & ENERGY RES. L. COURSE, St. Bar of Texas, Ch. 8 (2005) (hereinafter, "Hosey"); Clay Barton & Sky Andrew Scherer, *Litigation Issues Spawned by Arco v. Marshall*, 31st ANN. OIL, GAS & MIN. L. INST., Univ. of Texas School of Law, St. Bar OGERL Section (2005) (hereinafter, "Barton & Scherer"); Richard D. Watt, Donato Ramos, and John Beckworth, "*Royalty Litigation – Key Issues*," 19 TEX. OIL & GAS L.J., NOS. 1, 2, AND 3 (2005) (hereinafter, "Watt, Ramos, and Beckworth"); Allen D. Cummings, *Today's Marketing, Yesterday's Leases, Check Stub Statutes: The Perfect Storm?*, 30th ANN. OIL, GAS & MIN. L. INST., Univ. of Texas School of Law, St. Bar OGERL Section, Paper 8 (2004) (hereinafter, "Cummings"); Singletery, *Royalty Litigation on Processed Gas: Valuation, Post-Production Activities and the Marketable Condition Rule*, 55th ANN. INST. ON OIL & GAS L. 8-1 (2004); Jay G. Martin, *Summary of Law Applicable to the Implied Covenant to Market with Special Emphasis on Texas Law*, 28 OIL, GAS & ENERGY RES. L. SECTION REPORT, NO. 4, St. Bar of Texas, at 60 (2004) (hereinafter, "Martin I"); Robert Pezold, *Affiliates: No Longer a Useful Device?*, 27 OIL, GAS & ENERGY RES. L. SECTION REPORT, NO. 3, St. Bar of Texas at 53 (2003); Copeland, *Recent Trends in Energy Litigation*, 54th ANN. INST. ON OIL & GAS L. 15-1 (2003); Owen L. Anderson, *2001: A Royalty Odyssey*, 53^d ANN. INST. ON OIL & GAS L. 4-1 (2002); Elizabeth N. Miller, *Royalty Obligations in Today's Oil and Gas Market: A Texas Perspective*, 53^d ANN. INST. ON OIL & GAS L. 5-1 (2002); David E. Pierce, *Exploring the Jurisprudential Underpinnings of the Implied Covenant to Market*, 48 ROCKY MT. MIN. L. INST. 10-1 (2002); Daniel M. McClure, *Royalty Valuation and Payment Issues: Where Are We and Where Are We Headed?*, 48 ROCKY MT. MIN. L. INST. 11-1 (2002); David E. Pierce, *Recent Developments in Non-Regulatory Oil and Gas Law*, 53^d ANN. INST. ON OIL & GAS L. § 3.01 (2002); Petty and Hollimon, *A Practitioner's Perspective on Emerging Issues Relating to the Lessor-Lessee Relationship*, 28th ANN. OIL, GAS & MIN. L. INST., Univ. of Texas School of Law, St. Bar of Texas OGERL Section, Paper 5 (2002); Baldemar Garcia, Jr., *Royalty Update*, 20th ANN. ADV. OIL, GAS & ENERGY RES. L. COURSE, St. Bar of Texas, Ch. 20 (2002) (hereinafter, "Garcia"); Kris Terry, *Royalty Owner Theories of Lessee's Liability*

presented a paper on this subject at the Advanced Course in 1997 and published an update in the Section Report of the State Bar's Oil, Gas and Energy Resources Law Section in 2006.³ Another decade (approximately) having passed, the Planning Committee for this Advanced Course graciously invited me to provide a second update. In this paper, therefore, we will analyze the principles of gas royalty calculation and payment as they have evolved over the past several years, review some of the royalty calculation issues that are still unresolved, and discuss some possible solutions.

With limited exceptions, this article will not address oil and gas leases covering federally-owned or state-owned lands. In addition, except where expressly indicated, the discussion will focus on current Texas law.

for Under Payments, 20th ANN. ADV. OIL, GAS & MIN. L. INST., University of Texas School of Law, St. Bar OGERL Section, Paper 9 (2002); Alan Beliakoff, *The Practical Realities of Royalty Calculation*, 19th ANN. ADV. OIL, GAS & ENERGY RES. L. COURSE, St. Bar of Texas (2001); David E. Pierce, *Drafting Royalty Clauses*, 18th ANN. ADV. OIL, GAS & MIN. L. COURSE, St. Bar of Texas, Ch. 12 (2000); Elizabeth N. "Becky" Miller, *IMPLIED COVENANTS – AN UPDATE*, 17th ANN. ADV. OIL, GAS & MIN. L. COURSE, St. Bar of Texas, Ch. K (1999) (hereinafter, "Miller"); David E. Pierce, *Royalty Valuation Principles in a Changing Gas Market*, 11th ANN. ADV. OIL, GAS & MIN. L. COURSE, St. Bar of Texas (1993) (hereinafter, "D. Pierce"); Richard C. Maxwell, *Oil and Gas Royalties – A Percentage of What?*, 34 ROCKY MT. MIN. L. INST. § 15.01 (1988) (hereinafter, "Maxwell"). For a listing of additional law review and continuing legal education commentary on royalty calculation issues, see also Pearson II, *infra* note 3, at note 2.

³ Michael P. Pearson, *Royalty Calculation Issues in the Post Order 636 Gas Market*, 15th ANN. ADV. OIL, GAS & MIN. L. COURSE, St. Bar of Tex., Paper M (1997) (hereinafter, "Pearson I"); Michael P. Pearson, *Gas Royalty Calculation 2005 – An Update*, 30 OIL, GAS & ENERGY RES. L. SECTION REPORT, NO. 3, St. Bar of Tex., at 4 (2006) (hereinafter, "Pearson II"). See also Michael P. Pearson and Richard D. Watt, *To Share or Not to Share: Royalty Obligations Arising Out of Take-or-Pay or Similar Gas Contract Litigation*, 42^d INST. ON OIL & GAS L. & TAX'N 14-1 (1991) (hereinafter, "Pearson and Watt").

II. GAS MARKETING TODAY

Before undertaking our consideration of royalty calculation issues, a brief review of some history is in order because many of the current royalty calculation issues we grapple with were shaped by the various regulatory regimes in effect for natural gas over the years.⁴

A. Historical Gas Marketing Practices.

In the early days of the oil and gas industry, natural gas was generally regarded as an unwelcome by-product of oil production, rather than a valuable resource in its own right. Until the 1920s, most gas was flared at or near the wellhead.⁵ The discovery of the great Panhandle Field in Texas in 1918 ushered in an era in which the apparently vast reserves of natural gas available in the Panhandle Field became viewed as a clean and efficient source of heating and electric power generation fuel for cities and municipalities in other parts of the country. The evolution of this demand for gas sparked the construction of the large and complex “interstate” pipeline system, which by the end of World War II was transporting gas to residential heating, industrial, manufacturing, and power generation markets in the eastern and midwestern portions of the country.⁶ The development during and after World War II of a market for liquid hydrocarbons extracted from gas by processing further fueled the increasing demand for gas.⁷

⁴ For a more comprehensive treatment of the federal regulatory history of natural gas in the U.S., see Pearson I, *supra* note 3, at notes 2 through 49 and accompanying text; Pearson II, *supra* note 3, at notes 4 through 61 and accompanying text.

⁵ *Exxon Corp. v. Middleton*, 571 S.W.2d 349, 351 (Tex. Civ. App. – Houston [14th Dist.] 1978), *rev'd*, 613 S.W.2d 240 (Tex. 1981). See Cummings, *supra* note 2.

⁶ See *Exxon Corp. v. Middleton*, 571 S.W.2d at 351; Cummings, *supra* note 2, at 6.

⁷ See Cummings, *supra* note 2, at 6.

Because the pipelines provided the only path to move gas to its markets, the modern natural gas industry became premised upon the merchant role of the pipeline companies – that is, pipelines as purchasers of natural gas from the gas producers and as resellers of such gas to public utilities, industrial users, local distribution companies (“LDCs”), and other end users. By the late 1930’s, the United States government had become concerned about the development of the gas pipeline industry as a “natural monopoly,”⁸ in response to which Congress passed the Natural Gas Act of 1938 (“NGA”).⁹ The NGA subjected to the jurisdiction of the Federal Power Commission (“FPC”) so-called “natural gas companies” – primarily pipelines engaged in the transportation of gas in interstate commerce and/or the sale in interstate commerce of gas for resale for ultimate public consumption.¹⁰ The NGA did not establish federal jurisdiction over the production or gathering of gas, gas transportation solely within a single state (“intrastate” transportation), direct gas sales to end users, or the activities of LDCs.¹¹

Wellhead sales of gas did not become subject to the FPC’s jurisdiction under the NGA until the United States Supreme Court so ruled in *Phillips Petroleum Co. v.*

⁸ *A Brief History of Natural Gas Regulation*, FEDERAL ENERGY REGULATORY COMMISSION (May 19, 2010), <http://www.ferc.gov/students/energyweregulate/gas.htm>.

⁹ 15 U.S.C. §§ 717, et seq. (2014).

¹⁰ *Id.* at § 717a(6). The principal components of the FPC’s NGA regulation consisted of limiting the construction of new pipelines to those required by the “public convenience and necessity,” restricting the ability of natural gas companies to abandon their assets or service, *id.* at § 717f, and requiring that interstate pipeline transportation rates must be “just and reasonable,” *id.* at § 717c. See Jay G. Martin, *Federal Regulation of Natural Gas – A Primer*, 2ND GAS & POWER INST., Univ. of Texas School of Law, St. Bar OGERL Section, Paper 13, at 2, 3 (2003) (hereinafter “Martin II”).

¹¹ 15 U.S.C. § 717b.

Wisconsin in 1954.¹² As the result of *Phillips*, producers desiring to sell gas in the interstate market were required to obtain from the FPC certificates of public convenience and necessity pursuant to which their leases and leased acreage were dedicated to serve the interstate market,¹³ and the FPC was required to establish “just and reasonable” rates for such sales.¹⁴

As a result of this economic and regulatory structure, interstate pipelines sought to assure themselves of an acceptable return on the significant investment involved in pipeline construction and adequate supplies of gas for their customers by entering into long-term gas purchase contracts with producers (for the life of the underlying reserves, or, at a minimum, for terms of as much as 15-20 years) pursuant to which the producers committed to sell to the pipelines all of the gas produced from wells dedicated to the contracts. Producers desiring to sell gas in the interstate market embraced this approach because it gave them an assured market for their production which, in turn, facilitated their ability to obtain financing and otherwise to conduct their business planning from a position of economic

stability.¹⁵ The pipelines performed essentially all of the off-lease gas management services required to assure the delivery of the producer’s gas to the pipeline’s customers, including transportation, pooling, balancing, storage, exchanges, and similar functions.¹⁶

Ultimately, however, the FPC’s NGA-based regulation of wellhead gas sales proved incapable of responding in a timely manner to changing market conditions. Increasing prices for crude oil and oil products in the late 1960s and the early 1970s increased demand for natural gas. The artificially low gas prices applicable to gas sold in the interstate market, however, discouraged the development of new gas reserves and their dedication to interstate service. At the same time, the higher deregulated prices available for gas sold to intrastate pipelines incentivized producers to develop reserves for sale in that market. Consequently, by the late 1960s, there had evolved two separate and very distinct gas markets in most producing states – a lower-priced, highly regulated interstate gas market and a higher-priced, unregulated (or more lightly regulated) intrastate gas market.¹⁷

¹² 347 U.S. 672 (1954).

¹³ See 15 U.S.C. § 717f. Once a producer dedicated a lease or leased acreage to a certificate of public convenience and necessity, gas produced from the dedicated acreage was required to be sold in the interstate market until the FPC granted an abandonment under Section 7 of the NGA, *id.* at § 717f(b), even if, prior to such abandonment, the underlying sales contract had expired, *Sunray Mid-Continent Oil Co. v. FPC*, 364 U.S. 137 (1960), or the underlying oil and gas lease had expired, *California v. Southland Royalty Co.*, 436 U.S. 519 (1978).

¹⁴ *Phillips Petroleum Co. v. Wisconsin*, 347 U.S. 672, 684 (1954). See 15 U.S.C. §717c. Initially, the FPC attempted to establish well-by-well rates for these gas sales. As the backlog of individual well rate proceedings increased, however, the FPC first attempted to establish wellhead rates on an area-wide basis, see, e.g., *Permian Basin Area Rate Cases*, 390 U.S. 747 (1968), and *Area Rate Proceedings*, 50 F.P.C. 390, 392 (1973), and later on a nation-wide basis, see *Opinion 770*, 56 F.P.C. 509 (1976), and *Opinion, 770-A*, 56 F.P.C. 2698 (1976).

¹⁵ See Bruce M. Kramer, “*Royalty Obligations Under the Gun-The Effect of Take-or-Pay Clauses on the Duty to Make Royalty Payments*,” 39 INST. ON OIL & GAS L. & TAX’N 5-1, 5-4, 5-5 (1988) (hereinafter, “*Kramer*”); Edward B. Poitevent, II and Edsel F. Blanks, *Take-or-Pay: The Aftermath*, UNIV. OF HOUSTON L. CENTER ADV. OIL & GAS SHORT COURSE, at B-1 (1991) (hereinafter, “*Poitevent and Blanks*”).

¹⁶ See Carolyn Hazel, *The Gas Marketing Revolution: Sharing Values Between Lessors and Lessees*, 13TH ADV. OIL, GAS & MIN L. COURSE, St. Bar of Tex., Paper H, at H-1 (1995) (hereinafter, “*Hazel*”).

¹⁷ For good discussions of the evolution of the disparity between interstate and intrastate gas markets during this period, see Order No. 451, *Ceiling Prices: Old Gas Pricing Structure*, [Regs. Preambles 1986-90] F.E.R.C. STATS. & REGS. (CCH) 30,700; Martin II, *supra* note 10, at 3-5.

B. Movement Toward Price Deregulation

The first shots fired in the revolution in the U.S. gas market related to the decontrol of wellhead gas prices. In response to increasingly significant shortages of available natural gas supplies in the interstate gas market resulting from the bifurcated interstate/intrastate gas markets discussed above, Congress and the Federal Energy Regulatory Commission (“FERC”), which had succeeded to the regulatory responsibilities of the former FPC,¹⁸ undertook numerous legislative and regulatory initiatives intended to provide price and other incentives for increased production and sales of natural gas in the interstate market, including Congress’s enactment of the Natural Gas Policy Act of 1978 (“NGPA”).¹⁹

The NGPA established a series of “maximum lawful prices,” subject to statutorily prescribed annual escalations, applicable to several categories of newly drilled wells, regardless of whether gas from these wells was sold in the interstate or the intrastate markets, that would expire in 1985.²⁰ The NGPA also incorporated as separate categories of maximum lawful prices certain existing FPC/FERC approved rates applicable to existing gas production being sold into the interstate market,²¹ as

¹⁸ See Department of Energy Organization Act, Pub. L. No. 95-91, 42 U.S.C. §§7131, 7134 (2014).

¹⁹ 15 U.S.C. §§3301, *et seq.* (2014). See Pearson II, *supra* note 3, at 4.

²⁰ NGPA § 102 (new onshore wells), 15 U.S.C. §3312; NGPA § 103 (new onshore production wells), 15 U.S.C. § 3313; NGPA § 107 (high-cost natural gas), 15 U.S.C. § 3317; and NGPA § 108 (stripper well natural gas), 15 U.S.C. § 3318, *all repealed*, Pub. L. No. 101-60, § 2(b), 103 Stat. 158 (1989).

²¹ NGPA §§ 104 (existing interstate contracts) and 106 (rollover contracts), 15 U.S.C. §§ 3314, 3316, *repealed*, Pub. L. No. 101-60, § 2(b), 103 Stat. 158 (1989).

well as the prices being paid under existing intrastate gas sales contracts.²²

In large part, the NGPA worked. The separate and distinct interstate and intrastate gas markets, and their associated price disparities, were eliminated over a period of years, resulting in additional gas-focused exploration and development activity and the discovery of significant new gas reserves.²³

C. Continued Evolution of the U.S. Natural Gas Market

These increased gas reserves were a two-edged sword, however. By 1982, the increase in gas reserves, together with a world-wide recession, mild winters, and legislative and regulatory initiatives favoring the switching by industrial users to fuels other than gas, created a situation of weakened demand for, and excess supply of, gas.²⁴ These changed economic circumstances had adverse impacts on both the pipelines and their customers.

The principal source of the pipelines’ difficulties was the presence of so-called “take-or-pay” provisions in virtually all of their gas purchase contracts with producers. Take-or-pay provisions obligated a pipeline purchaser to take certain minimum quantities of gas on an annual basis (the “minimum contract quantity”), or, if the pipeline was unable to take all of the minimum contract quantity, to pay the producer for the difference between the minimum contract quantity and the volume of gas actually taken by the pipeline. Most contracts also gave the pipeline the right, over a period of succeeding years, to credit gas taken in excess of the minimum

²² NGPA § 105 (existing intrastate contracts), 15 U.S.C. § 3315, *repealed*, Pub. L. No. 101-60, § 2(b), 103 Stat. 158 (1989).

²³ See Pearson and Watt, *supra* note 3, at 14-6, 14-10; Pearson II, *supra* note 3, at 7.

²⁴ See Pearson II, *supra* note 3, at 7; Pearson and Watt, *supra* note 3, at 14-6, 14-8.

contract quantity for a particular year against previous take-or-pay payments.²⁵ As the demand for gas from the pipelines' end user customers decreased, the pipelines' economic exposure to producers under take-or-pay provisions increased dramatically. Pipelines adopted a range of responses to this circumstance, including unilateral reductions of the volumes of gas taken from producers and unilateral reductions in the price paid for gas taken. As a result of these actions, numerous lawsuits were filed by producers against pipelines pursuant to which producers sought damages for the pipelines' failure to comply with the take-or-pay and other provisions of the relevant gas purchase contracts and the repudiation by the pipelines of such contracts. With very few exceptions,²⁶ producers prevailed in these lawsuits.²⁷

In response to these changed conditions in the natural gas industry, the FERC and Congress implemented several legislative and regulatory initiatives intended further to reshape the natural gas industry. In a series of orders beginning in 1984, including Order No. 436 in 1985²⁸ and its landmark

Order No. 636 in 1992,²⁹ the FERC undertook, first, to transform the role of the interstate pipelines from the role of gas merchant to the more limited role of gas transporter,³⁰ and later, to require the unbundling of the interstate pipelines' sales and transportation services, which permitted pipeline shippers and customers to contract only for the specific service or services — such as dehydration, compression, treating, storage, and the like — required to transport that party's gas, thus lowering the transportation costs of the shipper or customer.³¹

During the same period, Congress passed the Natural Gas Wellhead Decontrol Act of 1989,³² pursuant to which all remaining NGA-regulated rates and NGPA maximum

²⁵ See *Diamond Shamrock Exp. Co. v. Hodel*, 853 F.2d 1159, 1164 (5th Cir. 1988).

²⁶ See, e.g., *Atlantic Richfield Co. v. ANR Pipeline Co.*, 768 S.W.2d 777 (Tex. App. — Houston [14th Dist.] 1989, no writ).

²⁷ E.g., *Universal Res. Corp. v. Panhandle Eastern Pipe Line Co.*, 813 F.2d 77 (5th Cir. 1987); *The Lenape Res. Corp. v. Tennessee Gas Pipeline Co.*, 925 S.W.2d 565 (Tex. 1996); *Valero Transmission Co. v. Mitchell Energy Corp.*, 743 S.W.2d 658 (Tex. App. — Houston [1st Dist.] 1987, no writ). See J. Michael Medina, et al., *Take or Litigate: Enforcing the Plain Meaning of the Take-or-Pay Clause in Natural Gas Contracts*, 40 ARK. L. REV. 185 (1986); David L. Roland, *Comment: Take-or-Pay Provisions for the Natural Gas Industry*, 18 ST. MARY'S L.J. 251 (1986).

²⁸ Order No. 436, *Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, [Regs. Preambles 1982-85] F.E.R.C. STATS. & REGS. (CCH) ¶30,665, *order on reh'g*, Order No. 436-A, [Regs. Preambles 1982-85] F.E.R.C. STATS. & REGS. (CCH) ¶30,675 (1985), *order on reh'g*, Order No. 436-B, [Regs. Preambles 1986-90] F.E.R.C. STATS. & REGS. (CCH) ¶30,688, *order on reh'g*, Order No. 436-C, 34

F.E.R.C. ¶61,404, *order on reh'g*, Order No. 436-D, 34 F.E.R.C. ¶61,405, *order on reh'g*, Order No. 436-E, 34 F.E.R.C. ¶61,403 (1986), *vacated and remanded sub nom. Associated Gas Distributors v. FERC*, 824 F.2d 981 (D.C. Cir. 1987), *cert. denied sub nom., Southern California Gas Co. v. FERC*, 485 U.S. 1006 (1988).

²⁹ Order No. 636, *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission's Regulations, and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, [Current] F.E.R.C. STATS. & REGS. (CCH) ¶30,939, *order on reh'g*, Order No. 636-A, [Current] F.E.R.C. STATS. & REGS. (CCH) ¶30,950, *order on reh'g*, Order No. 636-B, 61 F.E.R.C. ¶61,272 (1992), *reh'g denied*, 62 F.E.R.C. ¶61,007 (1993), *aff'd in part and remanded in part, United Distribution Cos. v. FERC*, 88 F.3d 1105 (D.C. Cir. 1996), *cert. denied sub nom., New York Public Service Comm'n v. FERC*, ___ U.S. ___, 117 S. Ct. 1723 (1997), and *Burlington Resources Oil & Gas Co. v. FERC*, ___ U.S. ___, 117 S. Ct. 1724 (1997).

³⁰ Order No. 436, [Regs. Preambles 1982-85] F.E.R.C. STATS. & REGS. (CCH) ¶30, 665, at 31,497-31,569. For an excellent discussion of Order No. 436, see Thomas G. Johnson, *Order No. 436 Revisited — The Interim Rule and Then What?*, 39TH INST. ON OIL & GAS L. & TAX'N 6-1 (1988).

³¹ Order No. 636, F.E.R.C. STATS. & REGS. (CCH) [Current] ¶30,939, at 30,402-13, 30,421-25, and 30,437-43.

³² Pub. L. No. 101-60, 103 Stat. 157 (1989) (codified in scattered sections of 15 U.S.C.A.).

lawful prices applicable to wellhead gas sales were eliminated by January 1, 1993.

A complete discussion of these FERC orders is beyond the scope of this paper.³³ Suffice it to say that the foregoing market, legislative, and regulatory developments utterly changed the face of the domestic natural gas industry. As wellhead prices became deregulated and the pipeline industry was restructured, a national free market for gas rapidly evolved. As a result, it is now possible readily to identify at any time the current market sale price, or “spot” price, for gas reported by both interstate and intrastate pipelines at any one of numerous locations on the national pipeline grid.³⁴ Technological advances have permitted the development of instantaneous electronic trading of both gas and pipeline capacity as truly fungible commodities.³⁵ Interstate pipelines now perform relatively few gas management functions, with most of these functions having been assumed either by gas producers or gas aggregators — marketing companies (that may be producer affiliates) that own no transportation facilities, but that purchase gas at the wellhead or in the field, arrange for transportation, engage in gas trading activities, and contract for the ultimate sale of the gas to an LDC or other end user. Under these circumstances, sales of gas in which producers are the sellers now generally fall into one of three general categories:

- wellhead sales to a gas processor, gas gatherer, or intrastate pipeline (each, a “Midstream Purchaser”), involving a commitment by the seller

³³ For a comprehensive summary of these actions by the FERC, see Pearson II, *supra* note 3, at 8-12.

³⁴ See Kathleen R. McLaurin, *New Financing Techniques in Gas Marketing*, 6TH ANN. OIL & GAS L. INST., S. Texas College of Law, Paper G, at G-2 (1993) (hereinafter “McLaurin”).

³⁵ See Hazel, *supra* note 16, at H-2, H-3.

of reserves to the contract, a “firm”³⁶ commitment by the purchaser to take the gas (usually up to a maximum daily quantity), and pricing based on a designated index price (plus or minus the applicable basis differential), with delivery to be made at the wellhead, one or more central delivery points in the field, or the inlet of a gas processing plant;

- short term sales, usually to gas aggregators, at daily index prices (plus or minus the applicable basis differential) at delivery points on the transporting pipeline, in most cases without a contractual commitment of reserves (“non-source specific”); and
- short, intermediate, or long term, non-source specific, direct, firm sales to end users, also known as “warranty contracts”, made at delivery points on the transporting pipeline or at the inlet of the purchaser’s facilities, at a fixed price, or at prices based on a designated index price (plus or minus the applicable basis differential) or a “forward” price curve based on gas futures prices on the New York Mercantile Exchange (“NYMEX”), or a combination thereof.³⁷

³⁶ “Firm” sales service is a higher class of service for gas that is continuous without curtailment except upon the occurrence of force majeure or other occasional, extraordinary circumstances. 8 Patrick H. Martin & Bruce M. Kramer, *WILLIAMS & MEYERS OIL & GAS LAW, Manual of Terms*, at 381 (2014).

³⁷ See Pearson II, *supra* note 3, at 12, 13; Hazel, *supra* note 16, at H-2, H-3; James C.T. Hardwick & J. Kevin Hayes, *Gas Royalty Issues Arising from Direct Gas Marketing*, 43^D ANN. INST. ON OIL & GAS L. & TAX’N 11-1, 11-8, 11-9 (1992) (hereinafter, “Hardwick and Hayes”). In the latter example, the gas price often reflects a premium over current index prices to compensate the seller for the additional risk assumed by the seller with respect to a longer term, firm sales obligation. In our experience, relatively few producers have participated in the Texas premium gas market because of the large volumes of gas typically required by the premium gas purchaser and

III. Principles of Royalty Calculation

Before undertaking our analysis of specific royalty calculation issues, it is appropriate to identify, to the extent we can, the basic legal principles of royalty valuation and calculation under Texas law. All inquiries concerning the calculation of royalties on gas production must begin with the terms of the royalty provisions of the applicable oil and gas leases. Although, under Texas law, a royalty interest is an interest in land, regardless of whether the royalty interest is payable in kind or money,³⁸ the typical lessor/lessee relationship is purely contractual in nature absent some other relationship between the parties created outside the lease.³⁹ As such, the incidents of ownership attributable to a royalty interest do not arise as matters of law but are defined as matters of contract to which the customary rules of contract interpretation are apply.⁴⁰

because of the flat-to-falling demand for new, large volume, long-term gas sales by electric power generators and other industrial gas consumers since the early 2000's.

³⁸ *E.g., Sheffield v. Hogg*, 124 Tex. 290, 77 S.W.2d 1021, 1027-28 (1934).

³⁹ *Potts v. Chesapeake Exploration, L.L.C.*, 760 F.3d 470, 473 (5th Cir. 2014); *Tittizer v. Union Gas Corp.*, 171 S.W.3d 857, 860 (Tex. 2005). See *Stinnett v. Colorado Interstate Gas Co.*, 227 F.3d 247, 253 (5th Cir. 2000) (“A fiduciary relationship is an extraordinary one and . . . does not abound in every, or even most, garden variety, arms-length contractual relationships, even those among trusting friends.”); *Hurd Enterprises, Ltd. v. Bruni*, 828 S.W.2d 101, 108 (Tex. App. – San Antonio 1992, *writ denied*) (“[U]nless the lease document itself creates in law a trust, or unless a relationship of trust and confidence necessarily results from the lessor-lessee relationship, the standard of conduct of the lessee cannot be appropriately categorized as fiduciary.”).

⁴⁰ *Potts v. Chesapeake Exploration, L.L.C.*, 760 F.3d 470, 473 (5th Cir. 2014); *Warren v. Chesapeake Exploration, L.L.C.*, 759 F.3d 413, 415 (5th Cir. 2014); *Heritage Resources, Inc. v. NationsBank*, 939 S.W.2d 118, 121 (Tex. 1996); *Killam Oil Co. v. Bruni*, 806 S.W.2d 264, 266 (Tex. App.-San Antonio 1991, *writ denied*).

The language contained in the royalty clauses of oil and gas leases is limited only by the imaginations of the scriveners who draft them. That said, to facilitate this analysis, we have adopted, for purposes of illustration and comparison, two (2) different forms of royalty clause. The first is found in the oil, gas and mineral lease in controversy in the landmark Texas Supreme Court decision in *Exxon Corp. v. Middleton*⁴¹ (the “Middleton Lease”). The royalty clause in the *Middleton Lease* (the “Middleton Lease Royalty Clause”) provides, in pertinent part, as follows:

The royalties to be paid by lessee are: . . . (b) on gas, including casinghead gas or other gaseous substances, produced from said land and sold or used off the premises, or used in the manufacture of gasoline or other products therefrom, by lessee, the market value at the well of 1/8 of the gas so sold or used, provided that on gas sold at the wells, the royalty shall be 1/8 of the amount realized from such sale; and (c) on fissionable materials and all other minerals mined and marketed, 1/10 either in kind or value at the well or mine, at Lessee's election, except that on sulphur mined or marketed, the royalty shall be Two Dollars (\$2.00) per long ton. . . .⁴²

The second illustrative royalty clause is found in the Pound Printing & Stationery

⁴¹ 613 S.W.2d 240 (Tex. 1982).

⁴² Exxon Company USA “Development 88” Lease Form No. 242-0052A. The *Middleton Lease Royalty Clause* is used in many different forms of oil and gas leases, including, for example, the AAPL Form 675 Oil and Gas Lease (Texas Form – Shut-In Clause, Pooling Clause).

Company “Producers 88 (4/76)” form of lease (the “4/76 Pound Lease”). This royalty clause (the “4/76 Royalty Clause”) provides, in pertinent part:

As royalty, lessee covenants and agrees: . . . (b) To pay lessor for gas and casinghead gas produced from said land (1) when sold by lessee, one-eighth of the amount realized by lessee, computed at the mouth of the well, or (2) when used by lessee off said land or in the manufacture of gasoline or other products, one-eighth of the amount realized from the sale of gasoline or other products extracted therefrom and one-eighth of the amount realized from the sale of residue gas after deducting the amount used for plant fuel or compression; (c) To pay lessor on all other minerals mined and marketed or utilized by lessee from said land, one-tenth either in kind or value at the well or mine at lessor’s election. . . .⁴³

An analysis of the lease royalty clause tells only part of the story, however. To fully understand the producer’s royalty payment obligation under an oil and gas lease, we must also understand the effect on this obligation of (a) the implied covenant to market and (b) the division orders executed by the royalty owner. Because the implied covenant to market is integral to most royalty owner claims for underpayment of royalty, the following analysis in Section III.A of this paper will focus first on the basic principles governing the operation of the implied covenant to market. Then Sections

⁴³ Pound Printing & Stationery Company Producers 88 (4/76) Revised Paid Up with 640 Acre Pooling Provision” Lease form.

III.B-G will discuss how the quantity of gas on which royalty is due is determined, the mechanics of the alternate royalty payment standards provided for in the *Middleton Lease Royalty Clause* and the *4/76 Royalty Clause*, the costs chargeable to the royalty interest, and, finally, the effect of division orders on the royalty analysis.

A. Marketing Covenant Analysis.

1. Implied Marketing Covenant - Generally.

Texas courts do not lightly or casually imply covenants in oil and gas leases. A covenant will not be implied unless it appears from the express terms of the lease that “it is so clearly within the contemplation of the parties that they deemed it unnecessary to express it”, or “it is necessary to infer such a covenant in order to effectuate the full purpose of the contract as a whole . . .” based on the four corners of the document.⁴⁴ The courts will not imply a covenant in order to achieve a fairer or more balanced agreement or to remedy a bad deal.⁴⁵

Historically, however, Texas law has generally recognized three broad categories of covenants implied in oil and gas leases which are intended to protect the interests of the lessor in connection with the development and protection of the lease and to discourage the lessee from considering only its own interests in the operation of the lease: (a) the covenant reasonably to develop the premises; (b) the

⁴⁴ *HECI Exploration Co. v. Neel*, 982 S.W.2d 881, 888-89 (Tex. 1998), quoting from *Danciger Oil & Ref. Co. v. Powell*, 137 Tex. 484, 154 S.W.2d 632, 635 (1941), and *Freeport Sulphur Co. v. American Sulphur Royalty Co.*, 117 Tex. 439, 6 S.W.2d 1039, 1041 (1928).

⁴⁵ *Id.* See also *Yzaguirre v. KCS Energy Resources, Inc.*, 53 S.W.3d 368, 373 (Tex. 2001); *Enron Oil & Gas Co. v. Joffrion*, 116 S.W.3d 215, 222 (Tex. App. – Tyler 2003, *no. pet.*); *Union Pacific Resources Group, Inc. v. Neinast*, 67 S.W.3d 275, 281 (Tex. App. – Houston [1st Dist.] 2002, *no. pet.*).

covenant to protect the leasehold; and (c) the covenant to manage and administer the lease.⁴⁶ Included within the covenant to manage and administer the lease is the covenant reasonably to market the oil and gas produced from the leased premises.⁴⁷ Once implied, such covenants become part of the lease and are just as binding as the expressed, written provisions thereof.⁴⁸ It is clear, however, that if the subject matter of an implied covenant conflicts with the express terms of the lease, the express terms of the lease will govern and control.⁴⁹ As stated by the Texas Supreme Court:

We have imposed implied covenants only when they are fundamental to the purposes of a mineral lease and when the lease does not expressly address the

subject matter of the covenant sought to be implied.⁵⁰

The implied covenant to market is two-pronged: the lessee must market the production with due diligence and obtain the best price reasonably possible.⁵¹ The diligence required is that which would be exercised by a reasonably prudent operator under the same or similar circumstances. Stated differently, reasonable diligence on the part of the lessee must conform to, and be governed by, what is expected of persons of ordinary prudence in the industry under similar circumstances, conditions, practices, and procedures. Among the factors to be considered in determining the lessee's marketing diligence are: (a) the availability of marketing facilities, such as the presence of pipelines and the efforts of the lessee in securing extensions of pipelines into the field; (b) the pressure and quality of gas as affecting its marketability; (c) the volume of gas produced; (d) the prevailing market price; and (e) the time and manner of performance of such acts as might result in marketing. What constitutes reasonable diligence ultimately is a question of fact.⁵²

⁴⁶ *Amoco Production Co. v. Alexander*, 622 S.W.2d 563, 567 (Tex. 1981); *Cabot Corp. v. Brown*, 754 S.W.2d 104, 106 (Tex. 1987); *Yzaguirre v. KCS Resources, Inc.*, 53 S.W.3d 368, 374 (Tex. 2001).

⁴⁷ *Cabot Corp. v. Brown*, 754 S.W.2d 104, 106 (Tex. 1987); *Parker v. TXO Production Corp.*, 716 S.W.2d 644, 646 (Tex. App. - Corpus Christi 1986, *no writ*). *Yzaguirre v. KCS Resources, Inc.*, 53 S.W.3d 368, 374 (Tex. 2001).

⁴⁸ *McCarter v. Ransom*, 473 S.W.2d 235 (Tex. Civ. App. - Corpus Christi 1971, *no writ*).

⁴⁹ *E.g., Gulf Oil Production Co. v. Kishi*, 129 Tex. 487, 103 S.W.2d 965 (1937) (lessee not obligated to drill greater number of wells than required under express drilling covenant in lease because to do so "would make an agreement for the parties upon a subject about which in their written contracts they expressly agreed."); *Danciger Oil & Refining Co. v. Powell*, 137 Tex. 484, 154 S.W.2d 632, 635 (1941) "[W]hen parties reduce their agreements to writing, the written instrument is presumed to embody their entire contract, and the court should not read into the instrument additional provisions unless this be necessary in order to effectuate the intention of the parties as disclosed by the contract as a whole."; *Yzaguirre v. KCS Resources, Inc.*, 53 S.W.3d 368, 373 (Tex. 2001) ("[T]here is no implied covenant when the oil and gas lease expressly covers the subject matter of the implied covenant."); *Union Pacific Resources Group, Inc. v. Hankins*, 111 S.W.3d 59, 71-72 (Tex. 2003); *Bowden v. Phillips Petroleum Co.*, 247 S.W.3d 690, 701 (Tex. 2008).

⁵⁰ *HECI Exploration Co. v. Neel*, 982 S.W.2d 881, 889 (Tex. 1998).

⁵¹ *Cabot Corp. v. Brown*, 754 S.W.2d 104, 106 (Tex. 1987).

⁵² *Piney Woods Country Life School v. Shell Oil Co.*, 539 F. Supp. 957, 973-74 (S.D. Miss. 1982), *aff'd in part, rev'd in part, and remanded*, 726 F.2d 225 (5th Cir. 1984), *cert. denied*, 471 U.S. 1005 (1985). For example, in *Occidental Permian Ltd. v. The Helen Jones Foundation*, 333 S.W.3d 392 (Tex. App. - Amarillo 2011, *pet. denied*), the court of appeals affirmed a district court judgment holding that there was insufficient evidence to support a jury verdict that the producer breached the implied covenant to market by continuing to sell high CO₂-content gas under pre-existing percentage of proceeds ("POP") gas sale contracts assumed by the producer upon its acquisition of the oil and gas leases in controversy. The court found that the producer paid royalties based on the proceeds it received under the POP contracts; there was no evidence that the POP contracts were unreasonable when executed by the

The implied covenant to market is clearly applicable to royalty on gas production calculated by reference to the amount realized by the lessee from the sale of such production.⁵³ In the case of an amount realized royalty standard, application of the implied covenant to market does not, however, imply an absolute duty to sell gas at market value. The Texas Supreme Court has recognized that, while the failure to sell at market value may be relevant evidence of a breach of the implied covenant to market, “it is merely probative and is not conclusive.”⁵⁴

Prior case law also indicated that the implied covenant to market was applicable to royalty on gas production calculated by reference to the market value of that production at the well.⁵⁵ In the case of a market value royalty standard, the Texas Supreme Court, in dicta in *Cabot Corp. v. Brown*, stated that the implied covenant to market obligated the lessee to obtain the “best current price reasonably available.”⁵⁶ More recently, in *Yzaguirre v. KCS*

Resources, Inc.,⁵⁷ however, the Texas Supreme Court expressly rejected the quoted dicta from *Cabot* and held that, because a lease providing for the payment of royalty based on the market value at the well establishes an objective basis for calculating royalty that is independent of the price actually received for the sale of the gas production, the implied covenant to market does not apply in this circumstance.⁵⁸ The holding in *Yzaguirre* and the several cases that have followed its holding will be discussed in the more detail in conjunction with our market value analysis in Section III.E.3 of this paper.

It should be emphasized that the lessee’s duty to the royalty owner under the implied covenant to market does not extend to maximizing the royalty owner’s receipts at the operator’s expense.⁵⁹ Thus, a lessee is not obligated by the implied covenant to market to install equipment to remove an impediment to marketing production unless the installation of the equipment and its subsequent operation could reasonably be expected, under all circumstances, to result in a profit to the lessee over and above the costs of equipment installation and operation.⁶⁰

prior operator; the plaintiff’s expert testimony failed to establish that the market value of the gas was greater than the price received under the POP contracts because the expert relied on non-comparable sales; and the plaintiff failed to prove what a reasonably prudent operator would have done differently under the same or similar circumstances. *Id.* at 402-03, 406-07. See also *Migl v. Dominion Oklahoma Texas Exploration & Production, Inc.*, 2007 WL 475318 (Tex. App. – Corpus Christi 2007, *no pet.*)

⁵³ *Id.*; *Amoco Production Co. v. First Baptist Church of Pyote*, 579 S.W.2d 280, 287 (Tex. Civ. App. - El Paso 1979), *writ ref’d n.r.e. per curiam*, 611 S.W.2d 610 (Tex. 1980).

⁵⁴ *Amoco Production Co. v. First Baptist Church of Pyote*, 611 S.W.2d 610 (Tex. 1980). See *Union Pacific Resources Group, Inc. v. Hankins*, 111 S.W.3d 69, 74-75 (Tex. 2003); *Yzaguirre v. KCS Resources, Inc.*, 53 S.W.3d 368, 374 (Tex. 2001).

⁵⁵ *Cabot Corp. v. Brown*, 754 S.W.2d 104, 106 (Tex. 1987); *Amoco Production Co. v. First Baptist Church of Pyote*, 579 S.W.2d 280, 287 (Tex. Civ. App. – El Paso 1979), *writ ref’d n.r.e. per curiam*, 611 S.W.2d 610 (Tex. 1980).

⁵⁶ *Cabot Corp. v. Brown*, 754 S.W.2d 104, 106 (Tex. 1987).

⁵⁷ 53 S.W.3d 368 (Tex. 2001).

⁵⁸ *Id.* at 374-75. Accord, e.g., *Bowden v. Phillips Petroleum Co.*, 247 S.W.3d 690, 701 (Tex. 2008); *Union Pacific Resources Group, Inc. v. Hankins*, 111 S.W.3d 69, 72-73 (Tex. 2003). See notes 330 through 338 and accompanying text, *infra*.

⁵⁹ 3 Patrick H. Martin & Bruce M. Kramer, WILLIAMS & MEYERS OIL AND GAS LAW, §654 at 678-79 & n. 5 (2014) (hereinafter, “WILLIAMS & MEYERS”).

⁶⁰ *Rhoads Drilling Co. v. Allred*, 123 Tex. 229, 70 S.W.2d 576, 585 (1934); *Freeman v. Magnolia Petroleum Co.*, 165 S.W.2d 111, 116 (Tex. Civ. App.-Amarillo 1942), *rev’d on other grounds*, 171 S.W.2d 339 (Tex. 1943) (lessee under no obligation to construct a treatment plant and transporting pipeline facilities because of the enormous costs (in excess of \$14,000,000) involved in the construction process). *Contra, Union Oil Co. of California v. Ogden*, 278 S.W.2d 246, 249 (Tex. Civ. App.-El Paso 1955, *writ ref’d n.r.e.*) (lessee held liable for failure to market gas with diligence when the lessee failed to lay a pipeline

2. Standard of Performance.

a. Prudent Operator Standard. The Texas Supreme Court has set forth the following standard of performance required of lessees with respect to all implied covenants:

The standard of care in testing the performance of implied covenants by lessees is that of a reasonably prudent operator under the same or similar facts and circumstances. The reasonably prudent operator concept is an essential part of every implied covenant. Every claim of improper operation by a lessor against a lessee should be tested against the general duty of the lessee to conduct operations as a reasonably prudent operator in order to carry out the purposes of the oil and gas lease.⁶¹

to the only available marketing outlet located one-half mile away). Regarding the subject of treatment facilities in particular, in *Maddox v. Texas Co.*, 150 F. Supp. 175, 180 (E.D. Texas 1957), the royalty owners complained that the lessee failed to employ a type of mechanical separator on the leased premises used by other operators in the vicinity to separate condensate from wet gas. The court rejected the royalty owners' argument and held that, since the lessee acquired title to all of the gas produced from the leased premises under the terms of the lease, the lessee was entitled to remove the gas from the leased premises and "to do with it as he saw fit" as long as he paid royalty in accordance with the provisions of the applicable lease. *Id.* See also *Armstrong v. Skelly Oil Co.*, 55 F.2d 1066, 1068 (5th Cir. 1932) (notwithstanding the fact that wet gas was not salable except for the extraction of gasoline, the court held the lessee to be under no obligation to erect a plant to treat the gas).

⁶¹ *Amoco Production Co. v. Alexander*, 622 S.W.2d 563, 567-68 (Tex. 1981). One commentator has characterized the prudent operator standard as follows:

...[T]he prudent operator has the same function in oil and gas litigation as the reasonable man standard has in negligence litigation....The prudent operator is

The prudent operator standard is a contractual duty, rather than a tort duty, and the breach of an implied covenant is therefore an action sounding in contract, not tort. As such, the lessee's breach of an implied covenant has been held not to support the recovery of exemplary damages absent the proof of an independent tort.⁶² In addition, the prudent operator standard is measured on a lease-by-lease basis and is not to be reduced as to one lessor because the lessee may have other lessors in the same field.⁶³

The Texas courts have adopted the reasonably prudent operator standard as the standard of performance required of lessees with respect to the implied covenant to market gas.⁶⁴ The standard is relatively simple to apply when the interests of the lessor and the lessee are directly aligned, so that the lessor and the lessee both benefit from the lessee's attempt to obtain the best price possible for the sale of gas. There has been significant litigation, however, about how this standard should be applied, or whether a different, higher standard should be applied, when the interests of the lessor and lessee relative to gas marketing begin to diverge.

a reasonable man engaged in oil and gas operations. He is a hypothetical oil operator who does what he ought to do not what he ought not to do with respect to operations on the leasehold...[T]he question is not what was meet and proper for [a particular operator] to do, given his peculiar circumstances, but what a hypothetical operator acting reasonably would have done, given circumstances generally obtained in the locality.

5 WILLIAMS & MEYERS, *supra* note 59, §806.3 at 42-42.1.

⁶² *Amoco Production Co. v. Alexander*, 622 S.W.2d 563, 571 (Tex. 1981). See *Jim Walter Homes, Inc. v. Reed*, 711 S.W.2d 617 (Tex. 1986).

⁶³ 622 S.W.2d at 569.

⁶⁴ *Cabot Corp. v. Brown*, 754 S.W.2d 104, 106 (Tex. 1987); *Parker v. TXO Production Corp.*, 716 S.W.2d 644, 646 (Tex. App.-Corpus Christ 1986, no writ).

b. Alternative Higher Standards. In this regard, royalty owners have consistently urged the application of a higher standard of performance to the implied covenant to market, such as a fiduciary standard or a standard based on the tort duty of good faith and fair dealing, the breach of which would support an award of exemplary damages.⁶⁵

The fiduciary standard contemplates fair dealing and good faith, rather than a legal obligation, but differs from a tort duty of good faith and fair dealing by requiring the fiduciary to place the interest of another party above his own.⁶⁶ To date, the Texas courts have refused to impose a fiduciary standard of performance in an implied covenant case.⁶⁷

Similarly, Texas law does not recognize a duty of good faith and fair dealing applicable generally to contractual relationships.⁶⁸ That duty calls for neither party to a contract to do anything which injures the right of the other party to receive the benefits of the

⁶⁵ See McCartney, *Implied Covenants – Ongoing and Emerging Issues*, ADV. OIL & GAS SHORT COURSE, Univ. of Houston Law Center, Paper K, at K-24, K-25 (1997) (hereinafter, “McCartney”).

⁶⁶ *Crim Truck & Tractor Co. v. Navistar International Transportation*, 823 S.W.2d 591 (Tex. 1992). According to former Chief Justice Greenhill, the confidential relationship necessary to give rise to a fiduciary duty must arise “before and apart from the agreement made the basis for the suit.” *Consolidated Gas & Equipment Co. v. Thompson*, 405 S.W.2d 333, 336 (Tex. 1966). See McCartney, *supra* note 65, at K-27.

⁶⁷ *E.g.*, *Cabot Corp. v. Brown*, 754 S.W.2d 104 (Tex. 1988); *Parker v. TXO Production Corp.*, 716 S.W.2d 644 (Tex. App. - Corpus Christi 1986, no writ); *Hurd Enterprises, Ltd. v. Bruni*, 828 S.W.2d 101 (Tex. App. - San Antonio 1992, writ denied); *Hutchings v. Chevron U.S.A., Inc.*, 862 S.W.2d 752, 760-61 (Tex. App. - Dallas 1993, writ denied). See *Stinnett v. Colorado Interstate Gas Co.*, 227 F.3d 247, 253 (5th Cir. 2000) (“A fiduciary relationship is an extraordinary one and . . . does not abound in every, or even most, garden variety, arms-length contractual relationships, even those among trusting friends.”).

⁶⁸ *E.g. English v. Fisher*, 660 S.W.2d 521, 522 (Tex. 1983).

agreement.⁶⁹ The Texas courts have recognized, however, that a tort duty of good faith and fair dealing may arise in cases involving certain “special relationships” in which there exists a position of unequal bargaining power between the parties to the contract or in which one party has exclusive control over the business of the other.⁷⁰

As in the case the fiduciary relationship, the Texas courts have not recognized the existence of such a special relationship between the lessor and lessee under an oil and gas lease in a case involving an alleged breach of the implied covenant to market. In *Hurd Enterprises, Ltd. v. Bruni*,⁷¹ the court of appeals rejected the royalty owners’ argument that there existed a confidential relationship between the royalty owner and the producer giving rise to a duty of good faith and fair dealing. In so holding, the court noted the purely contractual nature of the lessor-lessee relationship and stated that, absent other special circumstances, “as a matter of law . . . that no ‘confidential relationship’ existed between [the lessor and the royalty owner] as that term is presently defined in Texas law.”⁷²

c. Introduction of “Good Faith” to Marketing Covenant. Much of the support for royalty owners’ claims of a higher standard of performance for the lessee in implied marketing covenant cases in which the interests of the royalty owner and producer diverge derives from differing

⁶⁹ *Id.*

⁷⁰ *E.g.*, *Aranda v. Insurance Co. of North America*, 748 S.W.2d 210, 212-13 (Tex. 1988); *Arnold v. National County Mutual Fire Insurance Co.*, 725 S.W.2d 165, 167 (Tex. 1987). See *English v. Fisher*, 660 S.W.2d 521, 524 (Tex. 1983) (Spears, J., concurring). See generally McCartney, *supra* note 65, at K-25.

⁷¹ 828 S.W.2d 101 (Tex. App. - San Antonio 1992, writ denied).

⁷² *Id.* at 112, relying extensively on the Texas Supreme Court’s withdrawn opinion in *Texas Oil & Gas Corp. v. Hagen*, cited in note 73, *infra*.

interpretations of the references to “good faith” in *Amoco Production Co. v. First Baptist Church of Pyote*.⁷³

In *Pyote*, Amoco, the lessee under numerous oil and gas leases providing for the payment of gas royalties based on the amount realized standard, entered into a gas sales contract providing for a wellhead sale price of \$0.17 per Mcf.⁷⁴ Subsequently, Amoco agreed to commit twelve additional leases to the contract in exchange for the purchaser’s agreement to increase the wellhead sales price payable under the contract from \$0.17 per Mcf to \$0.70 per Mcf.⁷⁵ The lessors under the twelve additional leases, based upon evidence that the average market price in the area at the time their leases were added to the contract was \$1.30 per Mcf and not the contract price of \$0.70 per Mcf, filed suit against Amoco alleging that Amoco had breached the implied covenant to market by failing to contract for the highest price available for their gas production.⁷⁶

The court of civil appeals affirmed a district court judgment in favor of the royalty owners against Amoco, with both the district and appellate courts rejecting Amoco’s argument that it had no implied covenant to market in favor of the plaintiff/lessors because the amount realized royalty standard was applicable under their

leases.⁷⁷ In so holding, the court of civil appeals, in a rambling opinion, concluded that there is “an implied covenant to exercise good faith in the marketing of gas, and particularly so where the interests of the lessor and the lessee are not identical.”⁷⁸ The court noted that although the price increase from \$0.17 per Mcf to \$0.70 per Mcf was a substantial benefit for Amoco and the royalty owners under the leases originally committed to the gas sales contract, the price increase did not constitute a substantial benefit for the plaintiff/royalty owners, whose gas could have been sold for substantially higher prices.⁷⁹ According to the court, “[W]here the interest of the lessee and the lessor do not coincide, the lessee must be held to a stricter standard” in the performance of the implied covenant to market.⁸⁰

In a *per curiam* opinion, the Texas Supreme Court refused Amoco’s application for writ of error, finding no reversible error.⁸¹ In that opinion, the supreme court endorsed the court of civil appeals’ recognition of “an implied covenant by the working interest owner to act in good faith in marketing the gas of its royalty owners.”⁸²

d. Return to Reasonably Prudent Operator Standard. Subsequent Texas cases do not appear to have adopted the proposition suggested by *Pyote* that a

⁷³ 579 S.W.2d 280 (Tex. Civ. App. - El Paso 1979), writ *ref’d n.r.e. per curiam*, 611 S.W.2d 610 (Tex. 1980). See also *LeCuno Oil Co. v. Smith*, 306 S.W.2d 190, 192 (Tex. Civ. App.-Texarkana 1957, writ *ref’d n.r.e.*), cert. denied, 355 U.S. 907 (1957) (division orders obligating lessee to account to royalty owners based upon the “price received at the wells” held to require lessee to “exercise the highest good faith” in marketing gas).

⁷⁴ *Amoco Production Co. v. First Baptist Church of Pyote*, 579 S.W.2d 280, 282 (Tex. Civ. App.-El Paso 1979), writ *ref’d. n.r.e. per curiam*, 611 S.W.2d 610 (Tex. 1980).

⁷⁵ 579 S.W.2d at 283.

⁷⁶ *Id.*

⁷⁷ *Id.* at 287.

⁷⁸ 579 S.W.2d at 285.

⁷⁹ *Id.*

⁸⁰ *Id.* at 286.

⁸¹ 611 S.W.2d at 610.

⁸² *Id.* See also *Shelton v. Exxon Corp.*, 719 F. Supp. 537, 548-49 (S.D. Tex. 1989), *rev’d on other grounds*, 921 F.2d 595 (5th Cir. 1991) (federal district court held that lessee breached the implied covenant to market by failing to enter into a long-term intrastate gas sale contract prior to the enactment of the NGPA (which would have resulted in a higher price for the plaintiff’s gas) in order to minimize its cost of gas used to fulfill certain corporate warranty gas sale contracts of the lessee).

standard of performance higher than the reasonably prudent operator standard is required of lessees in implied marketing covenant cases. In *Texas Oil & Gas Corp. v. Hagen*,⁸³ the Texas Supreme Court addressed directly the apparent inconsistency between the standard of performance announced in *Pyote* and that announced in *Amoco Production Co. v. Alexander*.⁸⁴ In a footnote, the court recited its recognition in *Pyote* of an implied covenant to act in good faith in marketing gas and its subsequent decision in *Alexander* establishing the reasonably prudent operator standard as the standard of performance owed by lessees in all implied covenant cases. The court then stated:

Being the last pronouncement by this court on the question of the duty of lessees to their lessors, *Alexander* is dispositive on this issue.⁸⁵

The court continued by expressly rejecting standards based upon a fiduciary duty, a duty of highest good faith, a duty of utmost good faith, and a duty of good faith and fair dealing.⁸⁶ Subsequent Texas cases have

adhered to this rationale, with the result that it is now well established that the standard of performance required of the lessee under an oil and gas lease in connection with all implied covenants is that of a reasonably prudent operator under the same or similar facts and circumstances.⁸⁷

In this author's view, the best reading of the "good faith" language in *Pyote* is that given by Professor John Lowe, who argues that the reference to "good faith" is "just one aspect of the reasonably prudent operator standard."⁸⁸ According to Professor Lowe, the reasonably prudent operator standard has three elements, which require the lessee to "(1) act in good faith, (2) with competence, and (3) with due regard to the interest of the lessor as well as its own interest."⁸⁹ Lowe defines such good faith as "the avoidance of bad faith," which he states is generally implicit in any contract.⁹⁰ This analysis was cited with approval by the court of appeals in *Hurd Enterprises, Ltd. v. Bruni*,⁹¹ and is also consistent with the standard of performance established by the

S.W.2d 101, 112 (Tex. App.-San Antonio 1992, *writ denied*).

⁸⁷ *Bowden v. Phillips Petroleum Co.*, 247 S.W.3d 690, 699, n.4 (Tex. 2008); *HECI Exploration Co. v. Neel*, 982 S.W.2d 881, 889 (Tex. 1998); *Cabot Corp. v. Brown*, 754 S.W.2d 104, 106 (Tex. 1988); *Occidental Permian, Ltd. v. The Helen Jones Foundation*, 333 S.W.3d 392, 401-03 (Tex. App. – Amarillo 2011, *pet. denied*); *Migl v. Dominion Oklahoma Texas Exploration & Production Co.*, 2007 WL 475318 at 5 (Tex. App. – Corpus Christi 2007, *no pet.*); *Enron Oil & Gas Co. v. Joffrion*, 116 S.W.3d 215, 222-23 (Tex. App. – Tyler 2003, *no pet.*); *Hutchings v. Chevron U.S.A., Inc.*, 862 S.W.2d 752, 760 (Tex. App. - Dallas 1993, *writ denied*); *Hurd Enterprises, Ltd. v. Bruni*, 828 S.W.2d 101, 108 (Tex. App. - San Antonio 1992, *writ denied*); *Parker v. TXO Production Corp.*, 716 S.W.2d 644, 646 (Tex. App. - Corpus Christi 1986, *no writ*).

⁸⁸ Lowe, "Developments in Non-regulatory Oil and Gas Law," 39TH ANN. INST. ON OIL & GAS L. 1-1, 1-17, 1-18 (1988) (hereinafter "Lowe I").

⁸⁹ *Id.* at 1-18, note 68.

⁹⁰ *Id.* at 1-18.

⁹¹ 828 S.W.2d 101, 109 n.10 (Tex. App. - San Antonio 1992, *writ denied*).

⁸³ 683 S.W.2d 24 (Tex. App.-Texarkana 1984), *aff'd in part and rev'd in part*, 31 Tex. Sup. Ct. J. 140 (Tex. 1987), *judgmt and op. of Tex. Sup. withdrawn, judgmt of Tex. Civ. App. set aside, motion for reh. and cause dismissed as moot*, 760 S.W. 2d 960 (Tex. 1988).

⁸⁴ 622 S.W.2d 563, 567-68 (Tex. 1981).

⁸⁵ *Hagen*, 31 Tex. Sup. Ct. J. at 142, n. 2.

⁸⁶ *Id.* at 141-142. The Texas Supreme Court, on December 14, 1988, withdrew its original judgment and opinion of December 16, 1987, reported in 31 Tex. Sup. Ct. J. 140, and vacated the judgment of the court of appeals. *Hagen*, 760 S.W.2d 960 (Tex. 1988). The supreme court does not appear to have withdrawn the opinion of the court of appeals, however. The issuance and publication of the supreme court's original opinion in the Texas Supreme Court Journal, however, has substantially eliminated any remaining precedential value that the court of appeals' opinion may have had concerning the points as to which the supreme court ordered reversal. See *Hurd Enterprises, Ltd. v. Bruni*, 828

Texas Business and Commerce Code for contracts subject to the provisions thereof.⁹²

B. Production Subject to the Royalty Obligation.

Under both the *Middleton* Lease Royalty Clause and the 4/76 Royalty Clause, there are two triggering events for the obligation to pay royalty on gas production: (a) production of gas, and (b) the sale or use of the gas produced. Under Texas law, as in most states, the term “production,” as used in the royalty clause, means the actual physical severance of the mineral from the soil.⁹³ Similarly, under Texas law, the sale of gas that triggers the obligation to pay royalty occurs at the time when such gas is produced and delivered to the purchaser thereof, rather than at the time of the execution of the gas sales contract applicable to such gas.⁹⁴

⁹² See TEX. BUS. & COM. CODE ANN. §1.203 (Vernon 2014) (“Every contract or duty within this title imposes an obligation of good faith in its performance or enforcement.”).

⁹³ *Exxon Corp. v. Middleton*, 613 S.W.2d 240, 244 (Tex. 1981); *Alameda v. TransAmerican Natural Gas Corp.*, 950 S.W.2d 93, 97 (Tex. App. – Houston [14th Dist.] 1997, writ denied); *TransAmerican Natural Gas Corp. v. Finkelstein*, 933 S.W.2d 591, 596 (Tex. App. – San Antonio 1996, writ denied); *Mandell v. Hamman Oil and Refg. Co.*, 822 S.W.2d 153, 165 (Tex. App. – Houston [1st Dist.] 1991, writ denied); *Killam Oil Co. v. Bruni*, 806 S.W.2d 264, 267 (Tex., App. – San Antonio 1991, writ denied); *Monsanto Co. v. Tyrrell*, 537 S.W.2d 135, 137 (Tex. Civ. App.-Houston [14th Dist.] 1976, writ ref’d n.r.e.).

⁹⁴ *Exxon Corp. v. Middleton*, 613 S.W.2d 240, 244-45 (Tex. 1981); *Texas Oil & Gas Corp. v. Vela*, 429 S.W.2d 866, 871 (Tex. 1968). See TEX. BUS. & COM. CODE ANN. §2.107 (Tex. U.C.C.) (Vernon 2014) (a contract for the sale of minerals or the like, including oil and gas, is a contract for the sale of goods subject to Chapter 2 of the Texas U.C.C. if minerals are to be severed by the seller; until severance, however, a purported present sale of such minerals that is not effective as a transfer of an interest in land is effective only as a contract to sell). See also *Piney Woods Country Life School v. Shell Oil Company*, 726 F.2d 225, 234 (5th Cir. 1984), cert. denied, 471 U.S. 1005, 105 S. Ct. 1868 (1985).

It should be noted that the obligation to pay royalty is triggered not only by the production and sale of gas, but also by the production and use of gas. It is appropriate, therefore, to address how the quantity of gas production on which royalty is due is measured and the uses of gas that will trigger a royalty payment obligation. It is also appropriate to consider what constitutes “gas” for purposes of the royalty clause.

1. Gas Measurement Issues.

The measurement of gas production is enormously complex and highly technical, and a detailed discussion of this subject is beyond the scope of this paper and the ken of this author.⁹⁵ In the absence of specific lease language addressing the measurement of gas, in Texas, the provisions of the Texas Natural Resources Code and, in particular, the rules of the Railroad Commission of Texas (the “RRC”) govern these issues. Briefly, Section 88.052 of the Texas Natural Resources Code provides:

No person owning, leasing, operating or controlling an oil property in this state may permit the oil or gas produced to pass beyond the possession or control of that person to the possession or control of any other person without first accurately measuring the amount of the oil or gas and making and

⁹⁵ There are several excellent articles which address these issues in more detail than is possible here. See, e.g., Scott Lansdown, “*ARCO v. Marshall and the Lessee’s Obligations with Regard to the Measurement and Commingling of Production*,” 27th ANN. OIL, GAS & MIN. L. INST., Univ. of Texas School of Law, St. Bar of Texas OGERL Section (2001); Brian Sullivan, “*Update of Cases Bearing on Gas Measurement, Commingling, and Allocation*,” 20th ANN. ADV. OIL, GAS & ENERGY RES. L. COURSE, St. Bar of Texas, Ch. 17 (2002) (hereinafter, “Sullivan”); and Barton and Scherer, *supra* note 2.

preserving an accurate record of the amount.⁹⁶

The applicable rules of the RRC are Statewide Rules 26 and 27. Statewide Rule 27 provides that all natural gas production, except casinghead gas production, shall be measured separately for each completed interval in a gas well before the gas leaves the lease where produced, and the producer is obligated to report the volume produced from each completion to the RRC.⁹⁷ Currently, the applicable RRC form for reporting such production is RRC Form PR.⁹⁸ In reporting gas well production, the “full-well stream gas” shall be reported and charged against each gas well for allowable purposes.⁹⁹ According to Statewide Rule 26, when oil and gas are found in the same stratum or when a well classified as a gas well meets certain other criteria described in the rule, the operator is required to install an approved separator capable of separating the oil and liquid hydrocarbons from the gas.¹⁰⁰ All separated oil and other liquid hydrocarbons must be “adequately measured” to pipeline specifications and RRC regulations before such substances leave the lease where they were produced, except for gas production from wells for which the full well stream is moved to a plant or central separation facility. In that case, the full well stream is measured separately for each well completion before the gas leaves the lease where produced.¹⁰¹

⁹⁶ TEX. NAT. RES. CODE § 88.052 (Vernon 2014).

⁹⁷ 16 TEX. ADMIN. CODE § 3.27(a) (2014).

⁹⁸ RRC Form PR was published for use in 2005. Prior to the publication of RRC Form PR, gas production was reported pursuant to Rule 27 using RRC Forms P-1 and P-2. See *Hooks v. Samson Lone Star, Ltd. Partnership*, 2015 WL 393380 at 15 n. 12 (Tex. 2015).

⁹⁹ 16 TEX. ADMIN. CODE § 3.27(f). RRC rules do not define “full well stream” or “full well stream gas.”

¹⁰⁰ 16 TEX. ADMIN. CODE § 3.26(a) (2014).

¹⁰¹ *Id.* at § 3.26(a)(2).

Typically, when gas production leaves the well bore, it is immediately run through an on-lease, two- or three-phase separator that separates the raw gas production into either gas and liquid hydrocarbons or gas, liquid hydrocarbons, and water. The gas volume is then measured through an “orifice meter” before the gas leaves the lease.¹⁰² Orifice metering is the most commonly used method of measuring gas production. The orifice meter does not measure the volume of gas production in the same way that crude oil volumes are directly measured in a tank battery. Rather, the orifice meter measures certain characteristics of the gas, including the line pressure, differential pressure, and flowing temperature. From this data, the volume of gas production is calculated using standard mathematical formulas.¹⁰³ The accuracy of orifice measurements can be affected by several factors, including the presence of liquid hydrocarbons in the gas stream. Thus, an orifice meter measuring a full well stream may be expected to yield less accurate measurements than if the liquid hydrocarbons had been separated from the gas stream before measurement. RRC rules and industry practice have established methods of correcting for these inaccuracies.¹⁰⁴

When the economics of developing and producing a gas field will be enhanced by centralized, fieldwide separation and processing (rather than well-by-well separation), the RRC, “to prevent waste, to promote conservation, or to protect correlative to rights”, may approve surface commingling of gas produced from multiple

¹⁰² See Sullivan, *supra* note 95, at 5.

¹⁰³ See Sullivan, *supra* note 95, at 2; Barton & Scherer, *supra* note 2, at 2-3.

¹⁰⁴ See Sullivan, *supra* note 95, at 7. More advanced technologies, such as multi-path ultrasonic meters, may ultimately offer more accurate wet gas measurement than orifice meters. See Zanker, “*The Performance of a Multi-Path Ultrasonic Meter with Wet Gas*,” 18th NORTH SEA FLOW MEASUREMENT WORKSHOP (2000).

tracts and/or reservoirs,¹⁰⁵ coupled with an exception to the individual well separation requirements of Statewide Rule 26.¹⁰⁶ The RRC will only approve surface commingling under Statewide Rule 27 and an exception to the individual well separation requirements of Statewide Rule 26 if the operator demonstrates to the RRC a method of allocation of the commingled production among each owner of an interest in the wells whose production is to be commingled that “accurately attribute[s] to each interest its fair share of the aggregated production.”¹⁰⁷ Absent contrary information, the RRC will presume that an allocation based on the daily production rate for each well, determined and reported to the RRC by semi-annual well tests, will accomplish this objective.¹⁰⁸

It is easy to see how complaints about measurement inaccuracy resulting from orifice metering of full well stream gas production and the fairness of allocations of commingled production back to individual wells may form the basis for gas measurement-related claims of royalty owners. Interestingly, however, the only Texas appellate decision addressing these issues discovered by our research is *ARCO Oil & Gas Co. v. Marshall*,¹⁰⁹ the opinion for which was vacated in aid of settlement.

¹⁰⁵ 16 TEX. ADMIN. CODE § 3.27(e) (2014).

¹⁰⁶ *Id.* at § 3.26(a)(2). See text accompanying notes 100-101, *supra*.

¹⁰⁷ 16 TEX. ADMIN. CODE § 3.26(b)(3) (2014).

¹⁰⁸ *Id.* at § 3.26(b)(3)(A). Operators may test commingled wells annually after approval by the RRC of the operator’s written request demonstrating that annual testing will not harm the correlative rights of the working or royalty interest owners of the commingled wells. *Id.* at § 3.26(b)(3)(B).

¹⁰⁹ 30 S.W.3d 469 (Tex. App. – San Antonio 2000), opinion vacated, 2001 WL 22051. Because the court’s opinion was withdrawn following the settlement of the case by the parties, the opinion does not appear in the bound volume of the reporter or on any of the electronic databases. A copy of the slip opinion is available from the court of appeals upon request. Cause No. 04-97-01027-CV (Tex. App. – San Antonio, Aug. 16, 2000).

Because the *Marshall* opinion was vacated, it has no precedential value. A short consideration of its facts and principal holdings is, nevertheless, instructive.

In *Marshall*, ARCO elected to engage in RRC approved surface commingling of gas produced from the plaintiff’s and other parties’ leases prior to the separation of the gas and the liquid hydrocarbons and to pay royalty based on an allocation developed for such commingling plan. As the result of this plan, ARCO achieved several operational economies, including avoiding the need to install two orifice meters downstream of the field separation facilities at a cost saving of \$20,000.00 for each meter. The plaintiffs asserted that ARCO failed properly to measure gas production from their lease, breached the terms of the leases, violated applicable statutes and regulations, and committed fraud. At trial, the jury concluded that ARCO had not breached its leases with the plaintiffs, but had violated Section 88.052 of the Texas Natural Resources Code and Statewide Rule 27, had not accurately measured gas production from the plaintiff’s lease, and had committed fraud against the plaintiffs. The San Antonio Court of Appeals affirmed the trial court decision on these issues.

In particular, the court of appeals rejected ARCO’s argument that the plaintiffs’ claims based on violations of applicable statutes and regulations were not properly before the court because the RRC had primary jurisdiction over such matters, concluding that although the RRC has jurisdiction to determine whether ARCO breached the applicable gas measurement statutes and regulations, it lacked jurisdiction to address plaintiffs’ other claims, which included claims of breach of contract and fraud, and plaintiffs’ requests for the remedies of declaratory relief and damages.

The court also affirmed the trial court’s award of damages based on the plaintiffs’ argument that, since ARCO had not fashioned an allocation scheme that

established with reasonable certainty the quantities of gas and liquid hydrocarbons from the commingled stream that were attributable to the plaintiff's lease, ARCO owed royalty to the plaintiffs on the entire commingled gas stream under the confusion of goods doctrine.¹¹⁰ Concluding that the plaintiffs had established that their property had been commingled with ARCO's, the court then held that ARCO had failed to carry its burden to establish with reasonable certainty the volume of commingled gas on which the plaintiffs were owed royalty, notwithstanding the evidence introduced by ARCO at trial concerning its method of allocating production back to the plaintiffs' leases.

The paucity of gas measurement-based royalty disputes since *Marshall* may be attributable to the Texas Supreme Court's clarification, two years after *Marshall* was decided, of the issue of primary versus exclusive jurisdiction in *Subaru of America, Inc. v. David McDavid Nissan, Inc.*¹¹¹ According to the court in *Subaru*:

Trial courts should allow an administrative agency to initially decide an issue when: (1) an agency is typically staffed with experts

¹¹⁰ In support of this position, the plaintiffs cited the Texas Supreme Court's decision in *Humble Oil & Ref'g Co. v. West*, 508 S.W.2d 812 (Tex. 1974). In that case, the court held that a producer that had commingled produced gas with native gas in a gas storage reservoir was obligated to pay royalties to the land owner on all gas withdrawn from the storage reservoir because the producer had failed to establish with reasonable certainty the volume of gas reserves upon which the royalty owners would have been entitled to royalties in the absence of the injection of the storage gas. *Id.* at 819. On remand, the producer was able to establish, through expert testimony, the volume of native gas present in the storage reservoir prior to the commencement of storage operations, thus limiting the royalty owner's ultimate recovery to its royalty share of the native gas present in the reservoir. *Exxon Corp. v. West*, 543 S.W.2d 667 (Tex. Civ. App. – Houston [1st Dist.] 1976, *writ ref'd n.r.e.*). See Barton & Scherer, *supra* note 2, at 5, 6.

¹¹¹ 845 S.W.3d 212 (Tex. 2002)

trained in handling the complex problems in the agency's purview; and (2) great benefit is derived from an agency's uniformly interpreting its laws, rules and regulations, whereas courts and juries may reach different results under similar fact situations.¹¹²

The court further stated that if the primary jurisdiction doctrine requires a trial court to defer to an agency to make an initial determination, the trial court should "abate the lawsuit and suspend finally adjudicating the claim until the agency has an opportunity to act on the matter."¹¹³ Since *Subaru*, therefore, it appears that gas measurement disputes that might have ripened into claims for underpaid royalties have either been resolved administratively pursuant to contested proceedings before the RRC or settled.¹¹⁴

It is not uncommon, of course, for oil and gas leases to contain provisions that address gas measurement issues contractually.¹¹⁵ A very recent Texas Supreme Court decision demonstrates the care that must be taken to assure that the gas measurement provisions added to an oil and gas lease do not conflict with its royalty clause. In *Hooks v. Samson Lone Star, Limited Partnership*,¹¹⁶ a case dealing primarily with issues relating to overlapping pooled units, the royalty clause in Article III of the leases in controversy provided for (a) a royalty "on gas, including casinghead gas or other gaseous substances, produced" from the leased premises equal to 25% of the greater of "the market value at the wells of such gas" or "the price received therefor

¹¹² *Id.* at 221

¹¹³ *Id.*

¹¹⁴ See Sullivan, *supra* note 95, at 10.

¹¹⁵ See 3 WILLIAMS & MEYERS, *supra* note 59, §643.6 at 550-51.

¹¹⁶ 2015 WL 393380 (Tex. 2015).

by Lessee ...”, and (b) a royalty of 25% of “all other liquid hydrocarbons that may be produced from said land ...”¹¹⁷ A separate provision appearing later in the leases provided that “for purposes of calculating all royalties payable under Article III, ... all such royalty calculations shall be based on formation production as reported on Texas Railroad Commission forms P-1 and P-2.”¹¹⁸ Former RRC Forms P-1 and P-2¹¹⁹ required producers to report not only the volumes of gas and condensate produced from each well at the surface, but also the “formation production” – i.e., the total volume of gas as it existed in and was removed from the reservoir that corresponds to such volumes of produced gas and condensate. As a result, producers were required to convert the volume of condensate produced at the surface to an equivalent volume of gas in the reservoir.¹²⁰

The lessors argued that the “formation production” clauses in each lease required the lessee to pay royalty on the “formation production” (including both natural gas volumes and condensate volumes converted to equivalent gas volumes) as well as an additional royalty on the liquid condensate volumes produced at the

surface.¹²¹ The trial court agreed with the lessors’ “formation production” argument and awarded damages to the lessors for underpayment of royalties, but the Houston Court of Appeals (First District) reversed,¹²² and the Texas Supreme Court affirmed the court of appeals’ holding.¹²³ After concluding that the “formation production” clause was intended to ensure that the lessee paid royalties on the total volume that the lessee reports to the RRC, the supreme court stated:

The conversion [of volumes of produced condensate to an equivalent volume of gas] ensures that the [lessee] pays royalties on an appropriate volume of production, not that [the lessee] pays royalties on some production twice. In other words, the clause does not require that royalties be paid on everything as gas.¹²⁴

2. Gas Used in Operations.

Both the *Middleton* Lease Royalty Clause and the 4/76 Royalty Clause provide that royalty will be payable on gas “produced” from the leased premises and “used off the premises, or used in the manufacture of gasoline or other products therefrom.” We will discuss the royalty obligation on “gas used in the manufacture of gasoline or other products” in Section III.G of this paper¹²⁵, which deals with processed gas. At this point, it is appropriate to consider the royalty

¹¹⁷ *Samson Lone Star, Ltd. Partnership v. Hooks*, 389 S.W.3d 409, 436 (Tex. App. – Houston [1st Dist.] 2012), *aff’d in part, rev’d in part*, 2015 WL 393380 (Tex. 2015).

¹¹⁸ *Id.*

¹¹⁹ As discussed in note 98, *supra*, RRC Forms P-1 and P-2 were replaced by the RRC with current Form PR in 2005.

¹²⁰ *Hooks v. Samson Lone Star, Ltd. Partnership*, 2015 WL 393380 at 10 (Tex. 2015). Current RRC Form PR no longer requires producers to convert volumes of produced condensate into an equivalent volume of gas in the reservoir. According to the instructions for Form PR, “the RRC will automatically convert the volume.” TEX. R.R. COMM’N, INSTRUCTIONS FORM PR: MONTHLY PRODUCTION REPORT, available at <http://www.rrc.texas.gov/media/2646/formpr-instructions-final-02-2005.pdf>. In *Hooks*, the Texas Supreme Court expressly declined to interpret the meaning of “formation production” as used in current RRC Form PR. *Hooks*, 2015 WL 393380 at 15 n.12.

¹²¹ *Hooks v. Samson Lone Star, Ltd. Partnership*, 2015 WL 393380 at 10 (Tex. 2015).

¹²² *Samson Lone Star Ltd. Partnership v. Hooks*, 389 S.W.3d 409, 437 (Tex. App. – Houston [1st Dist.] 2012), *aff’d in part, rev’d in part*, 2015 WL 383380 (Tex. 2015).

¹²³ *Hooks v. Samson Lone Star, Ltd. Partnership*, 2015 WL 393380 at 11 (Tex. 2015).

¹²⁴ *Id.* at 10.

¹²⁵ See notes 483 through 551 and accompanying text, *infra*.

consequences for gas “used”, whether on or off the leased premises.

Gas is “used” when it is delivered or consumed.¹²⁶ As such, producers ordinarily use produced gas as fuel for oilfield equipment, such as compressors and field separation equipment, fuel for gas processing and treating facilities, and in connection with gas lift or similar operations where the gas is injected into the producing formation to “lighten” crude oil so that it can be produced without a pump,¹²⁷ to improve reservoir pressure, or otherwise to enhance production.

a. Use Off The Leased Premises.

Absent lease language to the contrary, a straightforward reading of the phrase “gas used off the leased premises” suggests that if produced gas is consumed as fuel or used in operations at locations off the leased premises, the gas should be royalty bearing. The available case law supports that view. For example, in *Piney Woods County Life School v. Shell Oil Co.*,¹²⁸ the lessee used gas produced from the plaintiffs’ oil and gas leases for, among other uses, fuel at its Thomasville, Mississippi, gas processing plant, which was not located on the plaintiffs’ leases. The plaintiffs’ leases contained royalty clauses identical to the *Middleton* Lease Royalty Clause and the 4/76 Royalty Clause. Citing the lease provisions requiring the payment of market value royalty on gas used off the lease, the Fifth Circuit concluded that the plant fuel was “gas used off the lease” and therefore subject to royalty.¹²⁹ Interestingly, the court also stated that the lessee was entitled to treat the amount of the royalty payments on

the plant fuel as costs of processing to be borne by the royalty and working interest owners according to their respective interests.¹³⁰ Similar results have been reached in a number of other cases.¹³¹

Please note, however, the different result reached by the San Antonio Court of Appeals in *Birnbaum v. SWEPI LP*,¹³² based primarily on the presence of unique lease language. In *Birnbaum*, the court of appeals affirmed the trial court’s judgment authorizing the lessee to deduct from the quantities of gas on which royalty was paid plant and compressor fuel used in a gas processing plant located off the leased premises, notwithstanding the absence of a lease clause make such gas non-royalty-bearing. The applicable royalty clause, which had been modified in settlement of a prior dispute between the lessors and lessee, provided for the payment of royalty on gas produced from the leased premises and used off the premises or sold based on a fraction of the “value” of such gas. The term “value” was defined as the volume of gas produced and used off the premises or sold, measured in MMBtu, multiplied by an agreed upon index price. The MMBtu of gas were to be determined at “the field delivery point(s)”, which, at the time of the litigation, were at the tailgate of the gas processing plant.¹³³ The court concluded that, based on the language of the royalty

¹²⁶ *Exxon Corp. v. Middleton*, 613 S.W.2d 240, 244 (Tex. 1981). See *Chesapeake Exploration, L.L.C. v. Hyder*, 427 S.W.3d 472, 482 (Tex. App. – San Antonio 2014), *aff’d*, 2015 WL 3653446 (Tex. 2015).

¹²⁷ See *Carter v. Exxon Corp.*, 842 S.W.2d 393, 395 (Tex. App. – Eastland 1992, *writ denied*).

¹²⁸ 726 F.2d 225 (5th Cir. 1984), *cert. denied*, 471 U.S. 1005 (1985).

¹²⁹ *Id.* at 241.

¹³⁰ *Id.*

¹³¹ E.g., *Judice v. Mewbourne Oil Co.*, 939 S.W.2d 133, 137 (Tex. 1996); *Chesapeake Exploration, L.L.C. v. Hyder*, 427 S.W.3d 472, 482 (Tex. App. – San Antonio 2014), *aff’d*, 2015 WL 3653446 (Tex. 2015) (Royalty clause required payment of royalty on “gas ... produced from the Leased Premises and sold or used on or off the Leased Premises”; the court of appeals stated, “When appellants use gas for fuel or other operations, royalty is owed on such volumes not solely because the gas is produced ... but because appellants also used or consumed such gas.”); *Carter v. Exxon Corp.*, 842 S.W.2d 393, 399 (Tex. App.— Eastland 1992, *writ denied*).

¹³² 48 S.W.3d 254 (Tex. App. – San Antonio 2001, *pet. denied*.)

¹³³ *Id.* at 255.

clause and the parties' awareness, when the royalty clause was amended, that plant and compressor fuel were being retained prior to the delivery of the gas at the tailgate of the plant, royalty was due only on the gas measured at the tailgate of the plant, and not on the plant or compressor fuel removed prior thereto.¹³⁴ Because of the unique nature of the language in the royalty clause in *Birnbaum*, the holding in that case should be limited to its facts.

b. Use On the Leased Premises; the "Royalty Free" Clause. With reference once again to the *Middleton* Lease Royalty Clause and the 4/76 Royalty Clause, a straightforward reading of the phrase "gas used off the leased premises" suggests that if produced gas is consumed as fuel or used by the lessee in operations on the leased premises, the gas cannot have been used "off the leased premises" and, therefore, should not be royalty bearing. We have not, however, identified any Texas cases that have addressed this circumstance in the absence of a so-called "royalty free" clause in the oil and gas lease in controversy.

The *Middleton* Lease contains a typical "royalty free" clause that provides that the lessee "shall have free from royalty or other payment the use of ... oil [and] gas ... produced from [the leased premises] in all operations which the lessee may conduct hereunder ... and the royalty on [oil] and [gas] shall be deducted after deducting any so used."¹³⁵ The operation of such a provision is demonstrated in *Tana Oil and Gas Corporation v. Cernosek*.¹³⁶ In *Tana*, a class action lawsuit in which the plaintiff royalty owners successfully achieved class certification, the royalty owners claimed underpayment of royalties under four separate, common royalty clauses,

¹³⁴ *Id.* at 259.

¹³⁵ For samples of other types of "royalty free" clauses, see 3 WILLIAMS & MEYERS, *supra* note 59, §644.5 at 575-76.

¹³⁶ 188 S.W.3d 354 (Tex. App. – Austin 2006, *pet. denied*).

including a 4/76 Royalty Clause and three other royalty clauses requiring the payment of royalty on gas produced from the leased premises based on the "amount realized by the lessee, computed at the mouth of the well", the "amount realized" from the sale of the produced gas if sold at the well, and "the net proceeds at the well received [by the lessee] from the sale ..." of such production.¹³⁷ The oil and gas leases in controversy also contained different forms of "royalty free" clauses, including two that were virtually identical to the quoted language from the *Middleton* Lease, one that was limited in scope to "gas lift operations on the leased premises", and one that was limited in scope to gas "used for operations on the pooled unit."¹³⁸ Among numerous other claims, the royalty owners alleged that the lessee had improperly failed to pay royalty on gas used in gas lift operations conducted by the lessee on the leased premises. The Austin Court of Appeals rejected the royalty owners' "gas lift" claims, stating that "[T]he plain language of these provisions authorizes [the lessee] to use gas produced from the leases in all operations. In addition, it is clear that [the lessee] was not required to pay royalty on any gas so used."¹³⁹

Is the operation of such a "free royalty" clause limited to the leased premises, or does it also apply to post-production operations – gas processing, for example – conducted off the leased premises? There is authority under Texas law for the proposition that a "royalty free" clause like that in the *Middleton* Lease applies to gas used in operations conducted both on and off the leased premises. In *Atlantic Richfield Co. v. Holbein*,¹⁴⁰ the lessor claimed that the lessee should pay royalty

¹³⁷ *Id.* at 357-58.

¹³⁸ *Id.* at 363.

¹³⁹ *Id.*

¹⁴⁰ 672 S.W.2d 507 (Tex. App.-Dallas 1984, *writ ref'd n.r.e.*).

on the total volume of gas produced from the well located on the lease measured at the wellhead, rather than on the sales volume delivered to the pipeline. The royalty clause in the lease had been superseded concerning the manner of royalty valuation by a subsequent royalty agreement between the lessor and the lessee, but the royalty agreement left untouched the lease's "royalty free" clause, which contained language identical to that in the *Middleton* Lease. A small percentage of the total gas production from the lease was apparently used off the leased premises as compressor fuel to permit the lease's gas production to enter the sales pipeline.¹⁴¹ In holding that the lessee owed no royalty to the lessor on the gas consumed as compressor fuel, the court agreed with the lessee's arguments that (i) the royalty agreement did not supersede the "royalty free" clause in the lease, and (ii) even if the "royalty free" clause was thus superseded, industry custom and practice called for the deduction of compressor fuel volumes in the calculation of royalty settlements, citing the practice set forth in the COPAS manual.¹⁴²

Subsequently in *Tana*, however, the Austin Court of Appeals appears to have taken a different approach. In addition to their "gas lift" claims for underpayment of royalty, the royalty owners in *Tana* also claimed that the lessee had improperly failed to pay royalty on gas produced from the leased premises and consumed as fuel at an off-lease gas processing plant.¹⁴³ The court of appeals

¹⁴¹ *Id.* at 515.

¹⁴² *Id.* at 515-16. Similarly, in *Mitchell Energy Corporation v. Blakely*, 560 S.W.2d 740 (Tex. Civ. App.-Fort Worth 1977, *writ ref'd n.r.e.*), the assignee of a 320-acre tract covered by a larger lease sold gas produced from the 320-acre tract to the owner of the remainder of the lease for use off the 320-acre tract in drilling operations on a nearby portion of the original leased premises. Treating the sale of gas as a sale off the leased premises, the court held that the sale of gas to the drilling party was not subject to royalty by operation of the "royalty free" clause in the lease. *Id.* at 744.

¹⁴³ *Tana Oil and Gas Corp. v. Cernosek*, 188 S.W.3d 354, 362 (Tex. App. – Austin 2006, *pet. denied*).

rejected the royalty owners' "plant fuel" claims, concluding that (i) the royalty obligations in the leases in controversy were triggered by either the sale of gas at the well or the sale of NGLs extracted by processing and residue gas, and (ii) since the gas consumed as plant fuel was never sold, no royalty obligation ever attached to such gas under the terms of the leases.¹⁴⁴ It is noteworthy, however, that the court reached its decision with respect to plant fuel consumed off-lease based solely on the language of the royalty clauses in the relevant leases without any reference to the "royalty free" clauses contained in such leases. To date, the Texas Supreme Court has not spoken directly on this issue.

3. Gas Lost and Unaccounted For.

A related issue concerns the royalty consequences for gas lost and unaccounted for under a royalty clause, like the *Middleton* Lease Royalty Clause or the 4/76 Royalty Clause, as to which the royalty obligation is triggered by gas "production" and "use". For this purpose, gas "lost and unaccounted for" ("LAUF") is defined as the quantity of gas equal to the difference between the volume of produced gas measured at the wellhead and the volume measured at the point of sale, after taking into account, to the extent applicable, gas consumed as fuel or in lease operations, condensate separated prior to processing, and "shrinkage" resulting from processing.¹⁴⁵

Unlike gas that is consumed as fuel or otherwise "used", oil and gas leases rarely address directly the issue of LAUF from a

¹⁴⁴ *Id.*

¹⁴⁵ See generally *Chesapeake Exploration, L.L.C. v. Hyder*, 427 S.W.3d 472, 481 (Tex. App. – San Antonio 2014), *aff'd*, 2015 WL 3653446 (Tex. 2015). See also Duane A. Harris, *Determining Lost and Unaccounted For Gas Loss*, available at <http://www.flocal.com/up-content/uploads/2012/02/Determining-Lost-and-Unaccounted-For-Gas-Loss.pdf>.

royalty standpoint.¹⁴⁶ The only case addressing this issue discovered by our research is *Chesapeake Exploration, L.L.C. v. Hyder*.¹⁴⁷ In *Hyder*, the royalty owners claimed, *inter alia*, that the lessee had improperly failed to pay royalty on LAUF.¹⁴⁸ The oil and gas lease in controversy provided that royalty was owed on gas “produced from the Leased Premises and sold or used on or off the Leased Premises.”¹⁴⁹ The San Antonio Court of Appeals affirmed the trial court’s rejection of the royalty owners’ LAUF claims, concluding that since gas that is lost and unaccounted for is neither “sold” nor “used”, such gas was not subject to royalty under the terms of the Hyders’ lease.¹⁵⁰ The Texas Supreme Court affirmed the court of appeals’ judgment in *Hyder* in its entirety without commenting specifically on the “LAUF” issue.¹⁵¹

4. Non-Hydrocarbon Substances in Gas Stream.

Clearly the gas royalty clause in the oil and gas lease applies to hydrocarbon natural gas produced from the leased premises. The gas stream from a particular gas well often includes, however, substances in gaseous form other than hydrocarbons, such as hydrogen sulfide, carbon dioxide, or helium. If these substances are extracted

from the hydrocarbon gas stream, the question arises whether additional royalty obligations accrue with respect to those substances. Assuming the applicability of a *Middleton* Lease or a 4/76 Lease, the answer to this question depends, in turn, on (a) whether the particular substance is within the grant of substances covered by the relevant lease, and (b) if so, whether the applicable royalty payment standard is that for royalty on gas contained in clause (b) of each of the *Middleton* Lease and the 4/76 Lease, or that for royalty on “other minerals mined and marketed” contained in clause (c) thereof.

a. Hydrogen Sulfide. With respect to hydrogen sulfide (“H₂S”), there is one Texas case in point. *Schwartz v. Prairie Production Co., Inc.*,¹⁵² dealt with the question whether royalty on H₂S-rich “sour” gas treated for the removal of sulphur should be paid under the gas royalty clause or on the elemental sulphur removed from the gas under the sulphur royalty clause¹⁵³. In the first appeal of this case, the court of appeals concluded that royalty should be paid under the gas royalty clause. According to the court, the proper inquiry was not how to pay royalty on the sulphur extracted from the sour gas, but how to pay royalty on the sour gas itself, and concluded that the sour gas should not be treated differently from any other gas produced under the relevant lease.¹⁵⁴ In the second

¹⁴⁶ For samples of lease clauses dealing directly with LAUF from a royalty standpoint, see 3 WILLIAMS & MEYERS, *supra* note 59, §644.5 at 576.1.

¹⁴⁷ 427 S.W.3d 472 (Tex. App. – San Antonio 2014), *aff’d*, 2015 WL 3653446 (Tex. 2015). In *Hooks v. Samson Lone Star, Ltd. Partnership*, 2015 WL 393380 (Tex. 2015), the royalty owners also claimed that the lessee improperly failed to pay royalty on LAUF but introduced no evidence to support such claim or to establish damages. As such, the Texas Supreme Court elected not to make a determination concerning whether the lessee’s failure to pay royalty on LAUF was improper. *Id.* at 10-11.

¹⁴⁸ 427 S.W.3d at 481-82.

¹⁴⁹ *Id.* at 476.

¹⁵⁰ *Id.* at 482.

¹⁵¹ 2015 WL 3653446 (Tex. 2015).

¹⁵² 727 S.W.2d 289 (Tex. App.-Houston [1st Dist.] 1987, *writ ref’d n.r.e.*), on remand, 833 S.W.2d 629 (Tex. App.-Houston [1st Dist.] 1992, *writ disp’d*).

¹⁵³ The royalty clause in the Schwartz’s oil and gas lease provided that: “As royalty, lessee covenants and agrees ... (b) To pay lessor on gas and casinghead gas produced from said land (1) when sold by lessee, ¼ of the amount realized by lessee, computed at the mouth of the well, or (2) when used by lessee off said land or in the manufacture of gasoline or other products, the market value, at the mouth of the well, of ¼ of such gas and casinghead gas; (c) To pay lessor on ... sulphur mined and marketed, the royalty shall be one dollar per long ton.” 833 S.W.2d at 631.

¹⁵⁴ 727 S.W.2d at 293. This result is consistent with those reached by the Fifth Circuit in *Scott Paper Co.*

appeal, after the district court on remand had conducted a trial on the merits and entered an instructed verdict in favor of Prairie on its claim that the sulphur royalty clause should apply, the court of appeals reversed the trial court's judgment and remanded the case for a new trial. After additional consideration, the court of appeals determined that the royalty clause in the oil and gas lease was ambiguous as to the provisions applicable to the sour gas and that a jury question had been presented.¹⁵⁵ There were no further appellate proceedings in this case. Thus, the issue remains unresolved in Texas with respect to H₂S.

b. Carbon Dioxide and Helium. In the case of carbon dioxide ("CO₂") and helium, the decisions of the federal courts and the courts of other states have consistently held that a grant or reservation of "all oil and gas" or equivalent language contained in a land patent, statute, deed, lease, or other document, absent an express reservation to the contrary, covers all components of the gas stream, including natural gas liquids, helium, and CO₂.¹⁵⁶ In *Commissioner of the*

v. Taslog, 638 F.2d 790 (5th Cir. 1981), and *First National Bank of Jackson v. Pursue Energy Corp.*, 784 F.2d 659 (5th Cir.), *vacated by* 799 F.2d 149 (5th Cir. 1986), *reh'g en banc denied*, 802 F.2d 455 (5th Cir. 1986). See *Piney Woods Country Life School v. Shell Oil Co.*, 726 F.2d 225, 229 n.3 (5th Cir. 1984), *cert. denied*, 471 U.S. 1005 (1985) ("It is clear, and Shell does not contest, that the royalty for elemental sulfur produced from sour gas is covered by the gas royalty clauses rather than the clauses providing for royalties on mined minerals.") See also, Maxwell, *supra* note 2, at 15-35 - 15-43.

¹⁵⁵ 833 S.W.2d at 632. See 1 Ernest E. Smith & Jacqueline Lange Weaver, TEXAS LAW OF OIL AND GAS § 4.6G at 4-109 (2014) (hereinafter, "SMITH & WEAVER").

¹⁵⁶ *Northern Natural Gas Co. v. Grounds*, 441 F.2d 704, 715 (10th Cir. 1971) (under the laws of Kansas, Oklahoma, and Texas, the grant contained in a conventional oil and gas lease of "oil and gas, casinghead gas, and casinghead gasoline" held to cover all components of gas stream, including helium, absent a specific reservation); *Carter v. Exxon Corp.*, 842 S.W.2d 393 (Tex. App.-Eastland 1992, *writ denied*) (natural gas liquids); *Aulston v. United States*, 915 F.2d 584, 599 (10th Cir. 1990) (reservations to

General Land Office v. Sandridge Energy, Inc.,¹⁵⁷ the only Texas case discovered by our research that addresses the royalty obligation under an oil and gas lease with respect to CO₂ native to the natural gas reservoir, the El Paso Court of Appeals appears to have assumed that the granting clauses in the oil and gas leases in controversy covered CO₂ in the gas stream without directly commenting on the issue.

Regarding the applicable royalty standard, the court in *Sandridge* addressed this issue directly in a complex, fact specific opinion that construed the royalty clauses in six (6) separate oil and gas leases, one of which covered Relinquishment Act lands and was executed by the General Land Office of the State of Texas ("GLO").¹⁵⁸ According to the court:

(1) Under the GLO lease and three other leases that contained gas royalty clauses similar to the *Middleton* Lease Royalty Clause that apply to "gas, including casinghead gas and other gaseous or vaporous substances" produced

the United States in federal land patents of "all oil and gas" pursuant to the Agricultural Entry Act of 1914, 30 U.S.C. §§121-125 (1995), included deposits of carbon dioxide); *Hudgeons v. Tenneco Oil Co.*, 796 P.2d 21, 23 (Colo. Ct. App. 1990, *cert. denied*) (reservation of "all oil and gas rights" included each and every type of "gas," including non-hydrocarbon substances such as carbon dioxide).

¹⁵⁷ 454 S.W.3d 603 (Tex. App. – El Paso 2014, *pet. filed*).

¹⁵⁸ *Id.* at 606-07. The lessee in *Sandridge* historically had processed gas produced from the leased premises for the removal of carbon dioxide, sold the extracted carbon dioxide, and paid the lessors a royalty on the proceeds. More recently, the lessee stopped paying royalty on its extracted carbon dioxide after it entered into a new processing arrangement at a larger, new plant operated by Oxy USA, Inc., pursuant to which the lessee delivered to Oxy all of the carbon dioxide extracted from the lessee's gas in consideration of Oxy's agreement not to charge the lessee a carbon dioxide treatment fee. Predictably, the lessors complained that the lessee's cessation of royalty payments on the extracted carbon dioxide was improper. *Id.* at 607.

from the leased premises,¹⁵⁹ but that did not provide for a specific royalty on substances extracted from the gas stream through processing,¹⁶⁰ the court held that under the *Middleton* lease-style gas royalty clauses construed by the court, a single royalty was payable only on “raw gas”, including all of its components, in its natural state, as it is produced from the leased premises and measured at the wellhead, and that no separate royalty was due on the CO₂ subsequently extracted by processing the raw gas.¹⁶¹

(2) Under the two remaining leases, both of which contained royalty clauses that established specific methods for calculating royalty on gas processed or

¹⁵⁹ *Id.* at 608, 620-21. The relevant language of paragraph 4(B) of the GLO lease, which is functionally equivalent to the quoted language from the *Middleton* Lease Royalty Clause, provides for the payment of royalty “on any gas (including flared gas), which is defined as all hydrocarbons and gaseous substances not defined as oil in subparagraph (A) above, produced from any well on said land (except as provided herein with respect to gas processed in a plant for the extraction of gasoline, liquid hydrocarbons or other products) ...” *Id.* at 608.

¹⁶⁰ The GLO lease actually contained two provisions, paragraphs 4(C) and 4(D), that addressed the issue of royalty on processed gas. Paragraph 4(C) specified the royalty on “processed gas”, which was defined as “any gas processed in a gasoline plant or other plant for the recovery of gasoline or other liquid hydrocarbons ...” *Id.* at 609-10. Paragraph 4(D) specified the royalty on “carbon black, sulphur or any other products produced or manufactured from gas (excepting liquid hydrocarbons) whether said gas be ‘casinghead’, ‘dry’, or any other gas, by fractionating burning or any other processing.” *Id.* at 610. Similarly, paragraph 3(c) of the “Longfellow” lease established a specific royalty on “condensate and other products extracted from gas in any type of plant” owned by non-affiliate third parties. *Id.* at 625. Because of the manner in which the case was plead, however, the plaintiff/lessors did not request declarations regarding whether separate carbon dioxide royalties were due under paragraph 4(C) or 4(D) of the GLO lease or paragraph 3(c) of the “Longfellow” lease. For that reason, the court of appeals did not formally address the operation and effect of such provisions. *Id.* at 611, 625.

¹⁶¹ *Id.* at 616, 621.

treated in a plant,¹⁶² the court found that the lessee owed the relevant royalty owners a separate royalty on CO₂ extracted from the raw gas stream by processing, payable according to the specific terms of the applicable lease provisions.¹⁶³

A petition for review of the court of appeals opinion in *Sandridge* has been filed with the Texas Supreme Court, but as of the publication date of this paper, the supreme court has not acted on the petition. The holdings in *Sandridge* are, however, consistent with other Texas cases that have held that, under oil and gas leases that do not make specific provision for the payment of royalties on liquids extracted from the gas stream through processing, royalty is paid based on the market value at the well or the amount realized at the well, as applicable, of the gas in its unprocessed state.¹⁶⁴

¹⁶² In addition to a *Middleton* lease-style gas royalty clause, the “Citation” lease provides for a royalty on “gas processed in an absorption or extraction plant” owned or operated by the lessor and a separate royalty on gas processed at such a plant owned by a third party. *Id.* at 617. Similarly, in the “South Piñon Fee” lease, which also contained a *Middleton* Lease-style gas royalty clause, provided for a separate royalty on “gas, casinghead gas, and other gaseous substances produced and saved from the Leased Premises and processed through or otherwise treated in any plant”, whether owned by the lessee or a third party. *Id.* at 623. Under this provision, a separate carbon dioxide royalty would be payable if the sum of the market values of the liquid hydrocarbons, residue gas, carbon dioxide, and other products extracted by processing, determined at the points where such gas and products are first sold, exceeds the market value of the raw gas at the inlet of the plant. *Id.*

¹⁶³ *Id.* at 620, 623.

¹⁶⁴ *E.g., Danciger Oil & Refineries, Inc. v. Hamill Drilling Co.*, 141 Tex. 153, 171 S.W.2d 321 (1943); *Carter v. Exxon Corp.*, 842 S.W.2d 393 (Tex. App.-Eastland 1992, writ denied). See also *Ashland Oil, Inc. v. Phillips Petroleum Co.*, 554 F.2d 381, 387 (10th Cir. 1977), cert. denied, 434 U.S. 921 (1977), on remand, 463 F. Supp. 619 (N.D. Okla. 1978), *aff'd in part and rev'd in part*, 607 F.2d 335 (10th Cir. 1979), cert. denied, 446 U.S. 936 (1980). (United States Court of Appeals for the Tenth Circuit, applying Oklahoma law, held that the royalty owners under an oil and gas lease that did not contain a specific royalty provision covering helium were entitled to receive

Two recent cases have addressed the question whether the lessee owes a royalty obligation with respect to CO₂ injected into a producing formation as part of a CO₂ flood operation and subsequently produced in a commingled state with crude oil and casinghead gas from wells affected by the CO₂ flood. In *Occidental Permian Ltd. v. The Helen Jones Foundation*,¹⁶⁵ Occidental Permian Ltd. (“OPL”) operated a CO₂ flood as a tertiary recovery project in the Slaughter Field in Hockley, Terry, and Cochran Counties, Texas.¹⁶⁶ Non-native CO₂ injected into the producing formation as part of the CO₂ flood was returned to the surface entrained in the casinghead gas produced in association with crude oil from the affected wells, extracted from the casinghead gas by processing at a plant specially constructed by OPL for that purpose (the “Mallet Plant”), and then re-injected into the producing formation. The royalty owners claimed, *inter alia*, that OPL owed royalty on the non-native CO₂ extracted from the casinghead gas at the Mallet Plant.¹⁶⁷

The Amarillo Court of Appeals rejected the royalty owners’ claim and held the OPL owed no royalty on the non-native CO₂.¹⁶⁸ Citing *Humble Oil & Refining Co. v. West*¹⁶⁹ as controlling precedent, the court concluded that, like the gas injected by the lessee into the underground storage reservoir in *West*, the non-native CO₂ injected by OPL into the producing reservoir as part of the CO₂ flood was the personal property of OPL before injection, and OPL’s

royalty on helium production from the leased premises based upon the gas royalty clause contained therein).

¹⁶⁵ 333 S.W.3d 392 (Tex. App. – Amarillo 2011, *pet. denied*).

¹⁶⁶ *Id.* at 396.

¹⁶⁷ *Id.* at 397-98.

¹⁶⁸ *Id.* at 411.

¹⁶⁹ 508 S.W.2d 812 (Tex. 1974). For a more detailed description of the facts and holding in *West*, see note 110, *supra*.

ownership of the CO₂ was not lost or altered by its injection into the producing reservoir or its subsequent production in association with, or extraction by processing from, the casinghead gas.¹⁷⁰

The Texas Supreme Court reached the same result in *French v. Occidental Permian Ltd.*,¹⁷¹ a case dealing primarily with the responsibility for the costs of removing non-native CO₂ from casinghead gas produced from a CO₂ flood tertiary recovery project. Based on facts substantially similar to those in *Helen Jones*,¹⁷² the supreme court concluded that, under the authority of *West*, “CO₂ injected into the Cogdell Field remains [the producer’s] property, and [the lessor] is not entitled to a royalty based on its value when it is produced with the casinghead gas.”¹⁷³

C. Alternative Royalty Payment Standards.

The *Middleton* Lease Royalty Clause establishes two different royalty payment standards, depending on whether gas is “sold or used off the premises, or used in the manufacture of gasoline or other products therefrom” or is “sold at the wells.” In the latter case, royalty is calculated based on the “amount realized from such sale”, while in the former case, royalty is calculated based on the “market value at the well ... of the gas so sold or used.” Although the 4/76 Royalty Clause determines royalty only by reference to the “amount realized”, it also contemplates two different payment standards by varying the point where the “amount realized” is determined – “at the mouth of the well”, if the gas is sold, and presumptively at the point of sale (the 4/76 Royalty Clause

¹⁷⁰ *Helen Jones*, 333 S.W.3d at 409-410.

¹⁷¹ 400 S.W.3d 1 (Tex. 2014).

¹⁷² For a more detailed discussion of the facts in *French*, see text accompanying notes 456 through 462, *infra*.

¹⁷³ *French*, 400 S.W.3d at 9.

doesn't specify a particular point of calculation) if the gas is "used by lessee off said land or in the manufacture of gasoline or other products."

The Texas courts first addressed the meanings of the phrases "at the well" and "off the premises" in the 1977 court of civil appeals decision in *Butler v. Exxon Corporation* ("Butler").¹⁷⁴ In *Butler*, the gas in controversy was delivered to the gas purchaser at the tailgate of Exxon's central separation, dehydration, and treatment facility in the Atkinson Gas Field in Karnes and Live Oak Counties, Texas, which was located approximately one hundred feet west of the boundary of the land from which the gas was produced.¹⁷⁵ In interpreting a royalty provision virtually identical to the *Middleton* Lease Royalty Clause (which provided for an "amount realized" royalty payment standard for gas sold "at the wells"), the El Paso Court of Civil Appeals expressly approved the trial court's findings of fact¹⁷⁶ to the effect that "the term 'at the wells' means gas delivery which occurs in the vicinity of the field of production where the wells are located. . . . [Delivery] need not occur at the 'Christmas tree' on top of the well casing, nor is there any requirement that delivery occur on the particular lease or unit from which the gas is produced."¹⁷⁷

In *Exxon Corporation v. Middleton*,¹⁷⁸ however, the Texas Supreme Court expressly rejected and disapproved the holding in *Butler*,¹⁷⁹ and concluded that the

¹⁷⁴ 559 S.W.2d 410 (Tex. Civ. App. – El Paso 1977, writ ref'd n.r.e.).

¹⁷⁵ *Id.* at 413.

¹⁷⁶ *Id.* at 416.

¹⁷⁷ *Id.* at 414.

¹⁷⁸ 613 S.W.2d 240, 243 (Tex. 1981).

¹⁷⁹ *Id.* at 244 ("To the extent the Court of Civil Appeals' interpretation of the royalty clause in *Butler*, *supra*, conflicts with our interpretation of this clause, it is disapproved.") The court also noted that its holding was consistent with the federal district court holdings in *Skaggs v. Heard*, 172 F. Supp. 813 (S.D. Tex. 1959) (sale of gas at the outlet of a compressor

phrase "off the premises" modifies both the words "sold" and "used" as they appear in the royalty clause, and that the "premises" referred to therein was the land described in the relevant oil and gas leases. Consequently, gas sold "off the premises" is gas sold outside the boundaries of the leased premises, and gas "sold at the wells" is gas sold at wells located within the leased premises, rather than at wells within the field in which the leased premises are located.¹⁸⁰ The supreme court continued by holding that, even when oil and gas leases have been included in a pooled unit, the "leased premises," for royalty calculation purposes, are determined not by reference to the entire unit, but to the lands covered by each individual lease in the unit.¹⁸¹

The phrase "at the well" has a second connotation that will become more relevant as we consider in more detail the costs borne by royalty interests. As stated by the United States Court of Appeals for the Fifth Circuit in *Piney Woods Country Life School v. Shell Oil Co.*¹⁸²:

. . . [T]he purpose of the distinction between gas sold at the well and gas sold off the lease . . . is to distinguish between gas sold in the form in which it emerges from the well, and gas to which value is added by transportation away from the well or by processing after the gas is produced. . . . When the gas

located on the leased premises, but not less than 320 feet from any well drilled thereon, constituted a sale "at the wells"), and *Kingery v. Continental Oil Company*, 434 F. Supp. 349 (W.D. Tex. 1977), *rev'd on other grounds*, 626 F.2d 1261 (5th Cir. 1980), *cert. denied*, 454 U.S. 1148 (1982) (sale of gas at pipeline interconnect 3½ miles from the exterior boundary of the leased premises was a sale "off the premises").

¹⁸⁰ *Middleton*, 613 S.W.2d at 243.

¹⁸¹ *Id.* at 251-52.

¹⁸² 726 F.2d 225 (5th Cir. 1984), *cert. denied*, 471 U.S. 1005 (1985).

is sold at the well, the parties to the lease accept a good-faith sale price as the measure of value at the well. But when the gas is sold for a price that reflects value added to the gas after production, the sale price will not necessarily reflect the market value of the gas at the well. . . .

“At the well” therefore describes not only location but quality as well. Market value at the well means market value before processing and transportation, and gas is sold at the well if the price paid is consideration for the gas as produced but not for processing and transportation.¹⁸³

Although *Piney Woods* was decided applying Mississippi law, the Texas Supreme Court expressly approved the Fifth Circuit’s analysis of these points in *Heritage Resources, Inc. v. NationsBank, Co-Trustee*.¹⁸⁴

D. Amount Realized; Proceeds.

1. Defined.

Under Texas law, it appears well established that the phrase “amount realized,” when used as a gas royalty payment standard, means the amount actually received by the lessee upon the

sale of gas. In *Holbein v. Austral Oil Co.*,¹⁸⁵ the lease in controversy provided for the payment of gas royalties based upon the “amount realized” standard. The lessee paid royalties to the lessors based upon the gross receipts received by the lessee from the sale of the gas to the purchaser. Such amount was, however, less than the amount provided for in the gas sales contract because of rate ceilings imposed by applicable orders of the FPC. The lessors filed suit to recover the difference between the royalty payments paid by the lessee based upon the proceeds received under the FPC rate orders and the higher royalty payments that would have been made had the payments be based on the contract price.¹⁸⁶

The district court rejected the lessors’ arguments, holding that all royalties had been properly computed, and the Fifth Circuit affirmed. According to the Fifth Circuit:

We fail to see anything mysterious in the words “amount realized” which requires reference to the gas purchase contract for clarification. The language means exactly what it says - [the lessee] need pay royalties only on the amount realized from their sales, even if FPC rate regulations put that amount at less than it would have been under the gas purchase contract.¹⁸⁷

¹⁸³ 726 F.2d at 231.

¹⁸⁴ 939 S.W.2d 118, 127 (Tex. 1996) (Owen, J. concurring). *Accord, Judice v. Mewbourne Oil Co.*, 939 S.W.2d 133, 135 (Tex. 1996); *Occidental Permian, Ltd. v. The Helen Jones Foundation*, 333 S.W.3d 380, 399 (Tex. App. – Amarillo 2011, *pet. denied*); *Tana Oil and Gas Corp. v. Cernosek*, 188 S.W.3d 354 (Tex. App. – Austin 2006, *pet. denied*).

¹⁸⁵ 609 F.2d 206 (5th Cir. 1980).

¹⁸⁶ *Id.* at 207-208.

¹⁸⁷ *Id.* at 208. *Accord, Warren v. Chesapeake Exploration, L.L.C.*, 759 F.3d 413, 417 (5th Cir. 2014); *Davis v. CIG Exploration, Inc.*, 789 F.2d 328 (5th Cir. 1986); *Bowden v. Phillips Petroleum Co.*, 247 S.W.3d 690, 699 (Tex. 2008); *Yzaguirre v. KCS Resources, Inc.*, 53 S.W.3d 368, 372-73 (Tex. 2001); *Occidental Permian, Ltd. v. The Helen Jones Foundation*, 333 S.W.3d 380, 399 (Tex. App. – Amarillo 2011, *pet. denied*); *Tana Oil and Gas Corp. v. Cernosek*, 188

Some royalty clauses, of course, do not utilize the phrase “amount realized”, but instead refer to the “proceeds” or the “gross proceeds” received by the lessee from the sale of the gas. The language differences are not, in and of themselves, material, however, because the Texas courts have treated the three terms as being synonymous.¹⁸⁸ It is important to note that the terms “amount realized”, “proceeds”, and “gross proceeds” are absolute concepts in that they do not contemplate a point of calculation, such as “at the well” or “at the tailgate of the plant.” As such, if royalty is calculated based on the “amount realized”, “proceeds”, or “gross proceeds” without an identified point of calculation, royalty will be based on the full amount received by the lessee for the sale of the gas without deduction of any costs prior to the payment of royalty.¹⁸⁹

Royalty clauses that refer to the “net proceeds” received by the lessee from the

S.W.3d 354, 360 (Tex. App. – Austin 2006, *pet. denied*); *Butler v. Exxon Corp.*, 559 S.W.2d 410, 416 (Tex. Civ. App.-El Paso 1977, *writ ref'd n.r.e.*) (the court of appeals expressly affirmed the district court’s finding of fact that “the amount realized from such sale[s] [constituted] the total proceeds received from the gas stream . . .”).

¹⁸⁸ *E.g.*, *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.”); *Judice v. Mewbourne Oil Co.*, 939 S.W.2d 133, 136 (Tex. 1996) (“The term ‘gross proceeds’ means the royalty is to be based on the gross price received by [the lessee].”); *Tana Oil and Gas Corp. v. Cernosek*, 188 S.W.3d 354, 360-61 (Tex. App. – Austin 2006, *pet. denied*) (“The terms amount realized, proceeds and net proceeds computed at the wellhead are synonymous; they refer to the money obtained in an actual sale.”).

¹⁸⁹ *See Warren v. Chesapeake Energy, L.L.C.*, 759 F.3d 413, 417 (5th Cir. 2014); *Chesapeake Exploration, L.L.C. v. Hyder*, 2015 WL 3653446 at 2-3 (Tex. 2015) (royalty clause entitling the lessor to a fraction of “the price actually received by Lessee” for gas produced from the leased premises, without an identified point of calculation, entitled the lessor to its royalty fraction of the full price received by the lessee for the sale of its gas without deduction of post-production costs).

sale of the gas, on the other hand, expressly contemplate the deduction of certain costs from the “proceeds” or “gross proceeds” prior to the payment of royalty based on the point of royalty calculation.¹⁹⁰ Thus, when used in conjunction with the phrase “at the well”, the “net proceeds computed at the mouth of the well” refer to an amount equal to the proceeds received by the lessee from the sale of the gas, after deducting all reasonable post-production costs incurred between the wellhead and the point of sale.¹⁹¹ As stated by the Fifth Circuit in *Ramming v. Natural Gas Pipeline Company of America*,¹⁹² “A royalty clause based on net proceeds should be interpreted as excluding costs incurred prior to production, but ‘costs incurred subsequent to production (those necessary to render gas marketable) are to be borne on a pro rata basis between operating and non-operating interests.’”¹⁹³

The same result is obtained with respect to the phrase “amount realized” by pairing it with the phrase “computed at the mouth of the well.” Indeed, this is the exact language found in the 4/76 Royalty Clause. In *Warren v. Chesapeake Exploration, LLC*,¹⁹⁴ the Fifth Circuit construed a lease containing such a 4/76 Royalty Clause.¹⁹⁵

¹⁹⁰ *Niemeyer v. Tana Oil and Gas Corp.*, 39 S.W.3d 380, 385-86 (Tex. App. – Austin 2001, *pet. denied*) (“Net” is defined as “free from all charges or deductions ... remaining after the deduction of all charges, outlay or loss ... opposed to gross.”)

¹⁹¹ *E.g.*, *Warren v. Chesapeake Exploration, L.L.C.*, 759 F.3d 413, 417-18 (5th Cir. 2014); *Martin v. Glass*, 571 F. Supp. 1406, 1411-15 (N.D. Tex. 1983), *aff’d*, 736 F.2d 1524 (5th Cir. 1984) (“Net proceeds” contemplates deductions.); *Judice v. Mewbourne*, 939 S.W.2d 133, 137 (Tex. 1996) (“‘Net proceeds’ expressly contemplates deductions, and ... ‘at the well’ means before value is added by preparing the gas for market.”); *Cartwright v. Cologne Production Co.*, 182 S.W.3d 438, 445 (Tex. App. – Corpus Christi-Edinburg 2006, *pet. denied*).

¹⁹² 390 F.3d 366 (5th Cir. 2004).

¹⁹³ *Id.* at 372.

¹⁹⁴ 759 F.3d 413 (5th Cir. 2014).

¹⁹⁵ *Id.* at 416.

After noting that “the term ‘amount realized’ requires measurement of the royalty based on the amount the lessee in fact receives under its sales contract for the gas ...,”¹⁹⁶ the court continued:

Had the lease provided only that the [lessors] are to receive 22.5% of the amount realized by lessee, there would be little question that the [lessors] would be entitled to 22.5% of the sales contract price that the lessee received, with no deduction of post-production costs. But that is not what the lease provides. There is a further proviso, which is that the amount realized is to be “computed at the mouth of the well.” This quantification of what the royalty shall be applies to all gas sold by the lessee, regardless of whether the gas is sold at the mouth of the well, off the leased premises, or at some point in between. The phrase “amount realized by Lessee, computed at the mouth of the well” means that the royalty is based on net proceeds, and the physical point to be used as the basis for calculating net proceeds is the mouth of the well. ... “[T]he phrase ‘net proceeds’ contemplates deductions.” Absent the addendum to the leases, the lessee was entitled to deduct from sales proceeds the reasonable cost of post-production costs incurred in delivering marketable gas from the

mouth of the well to the actual point of sale.¹⁹⁷

Please note, however, that the Texas Supreme Court has held that the phrase “gross proceeds realized at the well”, as used in a gas division order, was ambiguous. In *Judice v. Mewbourne Oil Co.*,¹⁹⁸ the trial court concluded that the relevant division order did not permit the lessee to deduct certain post-production compression costs. The supreme court reversed the trial court’s judgment, concluding that the quoted phrase was ambiguous. According to the court:

The term “gross proceeds” means that the royalty is to be based on the gross price received by [the lessee]. The use of the term “at the well” indicates just the opposite ... [V]alue at the well means the value of the gas before it has been compressed and before other value is added in preparing and transporting the gas to market. There is an inherent conflict in the use of the two terms that renders the clause ambiguous.¹⁹⁹

2. Take-or-Pay Settlement Cases.

As discussed in Section II.C of this paper,²⁰⁰ the litigation between the pipelines and the producers regarding the enforceability of take-or-pay provisions in gas purchase contracts dominated oil and gas-related litigation in the 1980s. Some of these disputes were litigated to judgment, usually in favor of the producers; others were settled, usually resulting in the producer’s receipt of a large settlement payment.

¹⁹⁶ *Id.* at 417.

¹⁹⁷ *Id.* at 417-18.

¹⁹⁸ 939 S.W.2d 133 (Tex. 1996).

¹⁹⁹ *Id.* at 136.

²⁰⁰ See notes 24 through 27 and accompanying text, *supra*.

These judgments and settlements, in turn, generated substantial litigation during the late 1980s and into the 1990s brought by royalty owners against producers seeking to establish that the take-or-pay payments themselves or the amounts of such judgments and settlement payments were royalty bearing.

Because, in Texas, the market value of gas is a hypothetical concept determined independently of the provisions of the applicable gas sale contract,²⁰¹ royalty owners subject to a market value royalty standard have been unable to establish the right, as a matter of law, to a share of any contract-related sums (like take-or-pay payments) except those representing the value of the gas itself. As a result, the royalty owner-producer take-or-pay litigation arose almost exclusively in the context of oil and gas leases providing for an amount realized royalty standard.

By now, most oil and gas practitioners are familiar with the lessons learned from these cases: (a) in Texas, the right to receive royalty is tied to the act of gas production; (b) if a particular payment represents “the fruits of the lessee’s production functions,”²⁰² the payment likely will be royalty-bearing; and (c) if, however, the payment reflects the entrepreneurial activities of the producer, such as marketing, transporting, or processing, the payment appears much less likely to be royalty-bearing.²⁰³ Because these cases provide a framework for analyzing similar royalty questions, however, a brief review of the principal royalty owner-producer take-or-pay decisions is appropriate.

²⁰¹ See notes 300 through 306 and note 341 and accompanying text, *infra*.

²⁰² John S. Lowe, *Defining the Royalty Obligation*, 49 SMU L. Rev. 223, 258 (1996) (“Lowe II”).

²⁰³ *Id.* at 257-58, 264-67.

a. Take-or-Pay Payments. In *Mandell v. Hammon Oil & Refining Co.*²⁰⁴, the Texas Court of Appeals affirmed a trial court judgment holding that a producer was not obligated to pay royalty on the portion of a gas contract settlement²⁰⁵ representing unpaid take-or-pay payments received by the producer from Tennessee Gas Pipeline Company.²⁰⁶ In so holding, the court stated that the obligation to pay royalty does not accrue until gas is actually produced - that is, physically severed from the land - and that take-or-pay payments do not represent payments for production. According to the court:

The purpose of a take-or-pay clause is to apportion risks of natural gas production and sales between the buyer and seller. The seller bears the risk of production, and the buyer agrees to take, or pay for if not taken, a minimum quantity of gas. The buyer bears the risk of market demand. The take or pay clause ensures that if the demand for gas decreases, the seller will still receive the price for the contract quantity delivered each year . . . A take or pay payment that comes before gas is actually

²⁰⁴ 822 S.W.2d 153 (Tex. App.-Houston [1st Dist.] 1991, *writ denied*).

²⁰⁵ The specific elements of the settlements reached by producers and pipelines concerning the take-or-pay disputes of the 1980s vary significantly, of course, from one transaction to the next. All of these settlements dealt in some fashion, however, with a number of common issues: the pipeline’s liability for underpayments for gas actually taken by the pipelines; the pipeline’s liability for take-or-pay payments and its corresponding right to recoup such payments out of future production; other concessions sought by the pipeline, including price reductions and reductions in the minimum contract quantity of gas required to be taken; and the continued effectiveness of the contract. See Pearson and Watt, *supra* note 3, at 14-16 – 14-18.

²⁰⁶ 822 S.W.2d at 166.

produced and taken cannot be a payment for the sale of gas.²⁰⁷

The court also rejected the royalty owner's claims that the producer's settlement of its take-or-pay dispute with the pipeline constituted a breach by the producer of the implied covenant to market. According to the court:

. . . [T]ake or pay is not a benefit that [the royalty owners] received via the execution of the lease with [the producer] and does not flow from the marketing covenant of the lease. [The producer] was required to obtain for [the royalty owners] only benefits received that were related to the sale of gas that had been produced.²⁰⁸

In *The Lenape Resources Corp. v. Tennessee Gas Pipeline Co.*,²⁰⁹ the Texas Supreme Court expressly endorsed the characterization of take-or-pay payments set forth in *Hammon*.

b. Contract Settlements. The remaining decisions in this line of Texas cases address the question whether non-recoupable cash settlement payments²¹⁰

²⁰⁷ *Id.* at 164-165.

²⁰⁸ *Id.* at 164-65.(emphasis in original).

²⁰⁹ 925 S.W.2d 565, 569-70 (Tex. 1996).

²¹⁰ In some contract settlements, pipelines received concessions with respect to price and/or minimum take obligations in exchange for the payment to the producer of cash or some other form of non-cash consideration, such as discounted or free transportation service. These types of settlements were known generally as "contract buydowns". Some contract buydowns included, as part of the consideration to the producer, the payment to the producer of a portion of the pipeline's unpaid take-or-pay payments, subject to the pipeline's right to recoup such payment out of future production delivered by the producer under the sales contract without paying additional consideration for the gas at the time of

received by producers in a take-or-pay dispute are royalty-bearing. The issue of recoupment in a contract buydown is significant in this analysis. If the gas purchaser has no right to recoup take-or-pay payments or settlement payments out of future production, royalty owners argue that the take-or-pay or settlement payments received by the producer effectively increase the price paid for the gas actually produced, so that royalty is owed on a current basis on the amounts of such payments.²¹¹

The seminal cases on these issues are the companion cases of *Killam Oil Co. v. Bruni* ("Bruni I")²¹² and *Hurd Enterprises, Ltd. v. Bruni* ("Bruni II").²¹³ In these cases, the producers entered into a "contract buyout" settlement²¹⁴ of take-or-pay disputes with United Texas Transmission Company ("UTTCO"), pursuant to which the producers agreed to release UTTCO from all claims for breach of contract and to cancellation of their gas contracts in exchange for lump

delivery. Settlement payments made in this type of contract buydown were said to be "recoupable". If the settlement payment in a contract buydown could not be recouped out of future production, the payment was said to be "non-recoupable". See Pearson and Watt, *supra* note 3, at 14-16 – 14-18.

²¹¹ See Pearson and Watt, *supra* note 3, at 14-46 - 14-49; Robert Grable, *Royalty and Division Order Issues – Gas Royalty Issues in a Revolutionary Gas Market*, 15th ANN. OIL, GAS & MIN. L. INST., Univ. of Texas School of Law, St. Bar of Texas OGERL Section, Paper 3 at 17 (1989).

²¹² 806 S.W.2d 264 (Tex. App.-San Antonio 1991, *writ denied*).

²¹³ 828 S.W.2d 101 (Tex. App.-San Antonio 1992, *writ denied*).

²¹⁴ "Contract buyouts" occurred when the producer and the pipeline determined that it was in their mutual best interest to discontinue their relationship. Contract buyouts ordinarily involved an agreement by the producer to release the pipeline from all take-or-pay liabilities in consideration of the producer's receipt from the pipeline of a cash settlement payment, accompanied by an agreement by the parties to terminate the sale contract. See Pearson and Watt, *supra* note 3, at 14-16 – 14-18.

sum cash settlement payments.²¹⁵ Thereafter, the royalty owner sued the producers seeking a royalty share of the settlement proceeds received from UTTCO based upon the theory that the take-or-pay provisions contained in the gas contracts constituted a constructive sale of gas. The royalty owner also sought damages based upon breach of the implied covenant to market, breach of the duty of good faith and fair dealing, fraud, conversion, unjust enrichment, and equitable reformation.²¹⁶

In *Bruni I*, the court of appeals reversed the judgment of the trial court in favor of the royalty owner and held that, “as a matter of law, the [royalty owner] is not entitled to royalties on the settlement proceeds arising from the take-or-pay provision of the contract between [the producers] and UTTCO.”²¹⁷ In so holding, the court stated:

This is not a suit by the [royalty owner] to recover royalties on the gas actually taken by UTTCO under the contract or on gas sold by [the producers] on the spot market. The dispute between UTTCO and [the producers] arose when UTTCO neither took the gas nor paid as required under the contract [Under the terms of the *Bruni* lease, the royalty owner] unambiguously limited its right to royalty payments only

from gas actually extracted from the land.²¹⁸

The court also rejected the royalty owner’s argument that the settlement payments received by the producers from UTTCO may have included underpayments of gas actually sold on the spot market. According to the court, take-or-pay payments do not represent any part of the price paid for produced gas, nor do they increase the price paid for gas that was taken. Rather, such payments “are made when gas is not produced”, and as such, bear no royalty.²¹⁹

In *Bruni II*, the producer Hurd and the royalty owner proceeded to a separate trial on the issues (a) whether the producer had breached the implied covenant to market, (b) whether there existed a confidential relationship between the producer and the royalty owner, and (c) whether the producer had breached its duty of good faith and fair dealing to the royalty owner by settling its dispute with UTTCO without consideration to the royalty owner.²²⁰ The jury (i) awarded the royalty owner a royalty share of the settlement proceeds paid to Hurd by UTTCO, (ii) found that there was no breach of the implied duty to market, and (iii) held that there did, in fact, exist a confidential relationship between the producer and the royalty owner that gave rise to a duty of good faith and fair dealing to the royalty owner that the producer breached by

²¹⁵ Brief of Appellees Fred M. Bruni, et al., at 6-7, *Killam Oil Co. v. Bruni*, 806 S.W.2d 264 (Tex. App.-San Antonio 1991, writ denied); brief of Appellant Hurd Enterprises, Ltd., at 9, *Killam Oil Co. v. Bruni*, 806 S.W.2d 264 (Tex. App.-San Antonio 1991, writ denied).

²¹⁶ Brief of Appellees Fred M. Bruni, et al., at 6, *Killam Oil Co. v. Bruni*, 806 S.W.2d 264 (Tex. App.-San Antonio 1991, writ denied).

²¹⁷ 806 S.W.2d at 268.

²¹⁸ *Id.* at 267-68.

²¹⁹ *Id.* at 268 (emphasis in the original). It is interesting to note that the court of appeals does not appear to recognize any distinction between a conventional take-or-pay payment and the cash settlement payments received by the producers from UTTCO pursuant to the buyouts of their respective contracts with UTTCO. Because the disputes between UTTCO and the producers arose out of UTTCO’s failure to make take-or-pay payments owed under the gas sale contracts, the court treats these cash settlement payments as if they were take-or-pay payments.

²²⁰ *Hurd Enterprises, Ltd. v. Bruni*, 828 S.W.2d 101, 104 (Tex. App.-San Antonio 1992, writ denied).

settling its dispute with UTTCO without consideration to the royalty owner.²²¹

On appeal, the court of appeals rejected the royalty owner's argument that the court reconsider its ruling in *Bruni I* in light of the then-recent Fifth Circuit decision in *Frey v. Amoco Production Co.*,²²² in which that court, applying Louisiana law, held that the plaintiff royalty owners were entitled to their royalty shares of all take-or-pay payments received by a producer pursuant to a take-or-pay settlement. Concluding that the royalty clause in controversy in *Bruni I* and *Bruni II*, which required actual production in order to trigger a royalty obligation, differed substantially from the royalty clause in the *Frey* lease,²²³ and because of the Texas Supreme Court's denial of the royalty owner's writ of error in *Bruni I*, the court applied the "law of the case doctrine" and held that the producer was not obligated to pay royalty on the proceeds of its settlement with UTTCO.²²⁴

In addition, the court of appeals reversed the judgment of the trial court and held that the relationship of the royalty owner and the producer was purely contractual in nature and that the producer did not owe the royalty owner any fiduciary duty or any duty of "highest good faith" or "utmost good faith" under the terms of the applicable leases.²²⁵

c. *Bruni II* Footnote 8. In footnote 8 of the *Bruni II* opinion, the court of appeals suggested that it might have reached a

²²¹ *Id.* at 104-05.

²²² 943 F.2d 578 (5th Cir. 1991), *op. withdrawn in part, question certified to La. S. Ct.*, 951 F.2d 67 (5th Cir. 1992), *cert. granted*, 592 So. 2d 1308 (La. 1992), *op. on cert. question*, 603 So. 2d 166 (La. 1992).

²²³ The oil and gas lease in controversy in *Frey* provided for the payment of royalty on "gas sold" by the lessee. 943 F.2d at 581-82. See 1 SMITH & WEAVER, *supra* note 155, § 4.6E at 4-99.

²²⁴ 828 S.W.2d at 106.

²²⁵ *Id.* at 112. See notes 70 through 72 and accompanying text, *supra*.

different result had the issue of recoupability been properly plead. According to footnote 8:

We recognize that there are cogent arguments concerning the royalty owner's interest in take-or-pay settlement funds, especially when, as here, the settlement terminates the purchaser's recoupment rights. One argument asserts that "if the gas purchase contract entitles the producer to retain take-or-pay proceeds, even though the pipeline never makes up the gas paid for, such proceeds have had the practical effect of increasing the price paid for gas actually produced. The lessor should be entitled to a royalty on these proceeds once the make-up right has terminated."... The recoupment issue, however, was not submitted in the case before us.²²⁶

The issues raised by *Bruni II* footnote 8 were the focal point of *TransAmerican Natural Gas Corp. v. Finkelstein*.²²⁷ In *Finkelstein*, the owner of an overriding royalty interest sought to recover his royalty share of certain non-recoupable repudiation damages received by a producer in a "contract buyout" settlement of a take-or-pay dispute with El Paso Natural Gas Company ("El Paso"). The repudiation damages were equal to the difference between the price that the producer would have received had El Paso not breached its take-or-pay obligations under the applicable gas contract and the price for which the

²²⁶ *Id.* at 106-07, n. 8.

²²⁷ 933 S.W.2d 591 (Tex. App.-San Antonio 1996, *writ denied*).

producer sold its gas on the spot market following El Paso's breach. The overriding royalty owner argued that, by failing to permit him to participate in the repudiation damages received from El Paso, the producer had breached its implied covenant to market.

Following a somewhat convoluted procedural history,²²⁸ the San Antonio Court of Appeals, the same appellate court that heard *Bruni I* and *Bruni II*, once again reversed the judgment of the trial court in favor of the overriding royalty owner and held that the overriding royalty owner was not entitled to participate in the non-recoupable settlement proceeds absent contractual language to that effect.²²⁹

In so holding, the court concluded that, under the terms of the agreements defining the overriding royalty owner's interests, his right to receive overriding royalty payments was unambiguously limited to gas actually extracted from the land.²³⁰ Noting that the overriding royalty owner's agreements were executed prior to and wholly independent of the El Paso gas sale contract and that the overriding royalty owner lacked privity of contract with El Paso, the court characterized the repudiation damages received by the producer as compensation to the producer for gas that was not taken or paid for under the gas sale contract.²³¹

²²⁸ Following a jury trial, the jury returned a verdict in favor of the royalty owner. The court of appeals initially affirmed the judgment and award of damages by the trial court. *TransAmerican Natural Gas Corp. v. Finkelstein*, No. 04-95-00365-CV, 1996 WL 148175 (Tex. App.-San Antonio 1996). On April 14, 1996, acting on a motion by the producer for rehearing, the court granted the producer's motion for rehearing *en banc*, withdrew its earlier opinion of April 3, 1996, and substituted a new opinion in its place. 933 S.W.2d at 593.

²²⁹ 933 S.W.2d at 593.

²³⁰ *Id.* at 598.

²³¹ *Id.*, citing *The Lenape Resources Corp. v. Tennessee Gas Pipeline Co.*, 925 S.W.2d 565, 570 (Tex. 1996).

The court also squarely rejected the royalty owner's argument, based on *Bruni II* Footnote 8, that the non-recoupable settlement proceeds were, in effect, compensation for gas production, and therefore royalty-bearing.²³² The court of appeals concluded that this issue "has been resolved by *Lenape's* explanation that take-or-pay payments represent compensation for producing and storing gas, not the mere 'pre-payment' of gas suggested by" the royalty owner.²³³ As such, the court stated that "the dicta in *Bruni II* is not controlling."²³⁴ Similar results were reached in *Alameda Corp. v. TransAmerican Natural Gas Corporation*²³⁵ and *Condra v. Quinoco Petroleum, Inc.*²³⁶

d. Participation in Judgments. In *Horwood v. Wagner & Brown II*,²³⁷ a case addressing the right of a royalty owner to participate in a judgment received by a producer in a take-or-pay case, the Austin Court of Appeals concluded that since the trial court's judgment was intended to represent money owed by the gas purchaser to the producer under the terms of the applicable take-or-pay provision, the judgment did not constitute money paid for gas produced and, therefore, was not royalty-bearing.²³⁸ The court also rejected the royalty owner's claim based on the

²³² 933 S.W.2d at 599.

²³³ *Id.*

²³⁴ *Id.*

²³⁵ 950 S.W.2d 93 (Tex. App. – Houston [14th Dist.] 1997, *writ denied*) (claim of non-participating royalty owner to participate in non-recoupable take-or-pay settlement rejected, since settlement payment, however characterized, was payment for non-production and therefore, non-royalty bearing).

²³⁶ 954 S.W.2d 68 (Tex. App. – San Antonio 1997, *writ denied*) (non-recoupable payment received as part of contract buy-down held not to be a payment for production and, therefore, not to be royalty-bearing).

²³⁷ 2001 WL 223282 (Tex. App. – Austin 2001, *no pet.*)

²³⁸ *Id.* at 3.

implied covenant to market, citing *Neel v. HECI Exploration Co.*,²³⁹ and stating that “neither the contemplation of the parties nor the purpose of the contract is sufficient to give rise to an implied covenant” relating to participation in the take-or-pay judgment.²⁴⁰

3. Payments to Producers Under Gas Sale Contracts.

Current gas sales contracts may provide for several different types of payments from one party to the other in addition to the commodity charge paid by the buyer to the seller for the gas, including “demand changes”, bonuses, management fees, and

²³⁹ 942 S.W.2d 212 (Tex. App. – Austin 1997), *rev'd in part*, 982 S.W.2d 881 (Tex. 1998). In *HECI*, royalty owners sued the producer to recover a royalty share of a damage award obtained by their lessee from the operator of an adjacent tract for lost reserves due to wrongful overproduction from the adjacent tract. The lessee of the royalty owners' lands had discovered the illegal drainage of their lands by the adjacent operator in 1985 and had initiated three separate proceedings before the Railroad Commission to stop the adjacent operator's overproduction. In 1988, the lessee filed suit against the adjacent operator and, in 1989, the trial court granted the lessee permanent injunctive relief against the adjacent operator and a judgment for both actual and punitive damages. The lessee never notified the royalty owners, however, of the adjacent operator's wrongful actions, the lawsuit, or its resolution. The royalty owners learned of the judgment obtained by their lessee more than four years later and filed suit to recover their royalty share of the judgment. 942 S.W.2d at 215.

In a complex opinion, the Texas Supreme Court reversed the judgment of the court of appeals in favor of the royalty owners, concluding that the “discovery rule” did not toll the running of the statute of limitations as to the royalty owners' claims, with the result that their claims were barred by limitations, 982 S.W.2d at 888, and entered a judgment that the royalty owners take nothing. *Id.* at 892. In so holding, the court concluded that there exists no implied covenant requiring a lessee to notify royalty owners of the lessee's intent to sue an adjoining operator, since such a duty is not necessary to effectuate the full purpose of the oil and gas lease and is not so clearly within the contemplation of the parties that they deemed it unnecessary to express it. *Id.* at 889-91. See notes 45 and 46 and accompanying text, *supra*; Pearson II, *supra* note 3, at 34-35.

²⁴⁰ 2001 WL 223282 at 3.

several types of liquidated damages. Against the backdrop of the take-or-pay settlement cases, it is now appropriate to address whether some or all of these non-commodity-charge payments are royalty bearing.

a. Demand Charges. Many gas sale contracts contain a two-pronged pricing provision that consists of (a) a commodity charge that establishes the price per MMBtu of delivered volumes of gas, and (b) a demand charge (often expressed as the product obtained by multiplying the maximum volume of gas deliverable on any day under the gas sale contract (“MaxDQ”) by the number of days in the month, by a specified charge) which is paid monthly regardless of the quantity of gas actually received by the purchaser.²⁴¹ The purpose of the demand charge is to compensate the seller for “standing by” to provide the purchaser with a reliable supply of gas as needed.²⁴²

Particularly when the applicable gas sale contract provides that the commodity charge and the demand charge should be added together to define the “price” payable for the gas, royalty owners are likely to argue that demand charges constitute a portion of the amount realized from the sale of the gas.²⁴³ According to the royalty owner, the purchaser has bargained for a firm supply of gas, and the linkage of these two elements in determining the contract price reflects that agreement.²⁴⁴

A closer analysis of the gas sale contract suggests a different analysis. In periods when the purchaser receives volumes of gas less than the MaxDQ, the purchaser

²⁴¹ See Garrett and Rollins, *Federal Royalty Valuation Issues in a Post FERC Order 636 Gas Marketing Environment*, 43 OIL & GAS TAX Q. 379, 402 (1995) (hereinafter, “Garrett and Rollins”).

²⁴² See Lowe II, *supra* note 202 at 254 n. 209.

²⁴³ *Id.* at 265 n.275.

²⁴⁴ See Garrett and Rollins, *supra* note 241, at 402.

nevertheless is obligated to pay the producer the full amount of the demand charge. The producer's argument is further strengthened if it can establish that the commodity charge reflects the full current market price for the gas sold. Under these circumstances, the demand charge seems more accurately characterized as compensation to the producer for the value of its guaranty of a reliable supply, rather than a payment for gas actually produced. Inherent in such a guaranteed performance is the risk that the producer will be unable to meet its obligations, a risk not shared by the royalty owner.²⁴⁵ If the producer is successful in establishing this characterization of a demand charge, the Texas take-or-pay settlement cases suggest that the demand charge should not be royalty bearing.

b. Deficiency-Based Demand Charge. The same result should obtain in the case of a demand charge that is payable only if the purchaser fails to receive the minimum contract quantity. Such a deficiency-based demand charge is arguably the functional equivalent of a take-or-pay payment. As such, we suggest that, under Texas law, such payments should not be treated as compensation for the sale of production, but as compensation to the producer for gas not taken, and therefore should not be royalty-bearing.²⁴⁶

c. "Load Management Fees" and "Supply Bonuses". If a producer/seller not

²⁴⁵ See Garrett and Rollins, *supra* note 241, at 403. See also *TransAmerican Natural Gas Corp. v. Finkelstein*, 933 S.W.2d 591, 599 (Tex. App.-San Antonio 1996, *writ denied*), in which the court states: "[t]he royalty owner, who does not 'shoulder the . . . risks of exploration, production, and development,' should not share in the take-or-pay payment. [citations omitted] Thus, [the royalty owner] cannot share in the right to the settlement proceeds without accepting corresponding duties."

²⁴⁶ *E.g. Mandell v. Hammon Oil & Refining Co.*, 822 S.W.2d 153 (Tex. App.-Houston [1st Dist.] 1991, *writ denied*); *Killam Oil Co. v. Bruni*, 806 S.W.2d 264 (Tex. App.-San Antonio 1991, *writ denied*).

only sells gas under a gas sales contract but also undertakes the obligation to perform various "gas management" services – *i.e.*, the arrangement for transportation, the performance of pipeline nominations, injection and withdrawal of gas from storage, and the performance of pipeline balancing - the purchaser typically compensates the producer/seller for the performance of these services the payment of a "load management fee".²⁴⁷ The gas sale contract may also provide for the payment to the seller of a "supply bonus" if the seller's performance exceeds certain specified goals stated in the contract.²⁴⁸ Applying the rationale of the take-or-pay settlement cases, neither the load management fee nor the supply bonus appears to have any relation to the production of gas. Both payments compensate the seller for his entrepreneurship in marketing the gas. As such, we suggest that such payments should not be royalty bearing.

d. Liquidated Damages. Many forms of gas sale contracts, particularly those with gas aggregators and end users as the gas purchasers, contemplate the payment of liquidated damages by the parties in certain circumstances.²⁴⁹ The most common forms of liquidated damages payable by purchasers to producer/sellers under these contracts are "cover" damages and "termination" damages.

Typically, "cover" damages are payable by the purchaser to the seller when the purchaser fails to receive the minimum contracted-for quantity of gas ("MinDQ") on

²⁴⁷ See Garrett and Rollins, *supra* note 241, at 404.

²⁴⁸ See *Lowe II*, *supra* note 202, at 228 n. 28.

²⁴⁹ The most popular "industry standard" form of gas purchase contract used by gas aggregators and end users is that promulgated by the North American Energy Standards Board. See NAESB Base Contract for Sale and Purchase of Natural Gas adopted on September 5, 2006 (minor correction applied 09/19/2011), available at <https://www.naesb.org/wgq/cont.asp>.

any day during the contract term. The measure of these “cover” damages is, generally speaking, the difference between the proceeds that the seller would have received under the existing contract had the purchaser received the full MinDQ and the price that the seller received for its sale of the untaken volumes to a third party, plus reimbursement for the seller’s associated out-of-pocket expenses.²⁵⁰ On balance, since cover damages accrue immediately upon the purchaser’s breach of the applicable gas contract and relate directly to the economic loss suffered by the producer/seller if it sells the untaken volumes of gas for a price less than that provided in the existing contract, the take-or-pay settlement cases suggest that at least the portion of the cover damages related to price should be treated as royalty-bearing.

Upon an event of default under most gas aggregator and end user gas sale contracts, the non-defaulting party is given the right to terminate the gas sale contract and to receive liquidated damages from the defaulting party in the form of a “termination” payment. Typically, termination payments are calculated as the positive difference between the value of the existing gas sale contract on the termination date and the value of a replacement contract obtained by the non-defaulting party following termination. In this regard, the termination payment is analogous to the non-recoupable repudiation damages in controversy in *TransAmerican Natural Gas Corp. v. Finkelstein*.²⁵¹ In that case, the court held that the producer was not required to share with the plaintiff overriding

royalty owner any portion of such non-recoupable repudiation damages.²⁵²

4. Derivatives and Futures Trading.

If a producer/seller hedges its price risk with respect to its gas production through the purchase of a futures contract or some form of derivative, the producer may receive economic benefits from the hedge transaction that do not translate into direct economic benefits for the royalty owner. The question thus arises whether the economic benefits derived by a producer from a hedging transaction constitute a part of the amount realized by the producer from the sale of its gas.

a. Derivative Transactions. Since the great majority of independent producers have in place some sort of revolving credit facility, the hedging activities of most independent producers must comply with the affirmative and negative covenants in their respective credit agreements. These covenants typically (a) require the producer to enter into hedging transactions with respect to a minimum percentage (*i.e.*, 80%) of its anticipated total production attributable to the proved reserves reflected in the most recent petroleum engineer’s report of estimated oil and gas reserves delivered to the producer’s lenders and (b) prohibit the producer from entering into hedging transactions with respect to more than a maximum percentage (*i.e.*, 90%) of such anticipated total production. The purposes of these covenants are, obviously, to require the producer to provide the lenders a form of insurance policy against commodity price risk (thereby enhancing the likelihood that the loan will be repaid) while restricting the ability of the producer to engage in speculation.²⁵³

²⁵⁰ For the standard for determining cover damages generally applicable to sales of goods under the Uniform Commercial Code, see TEX. BUS. COM. CODE ANN. §2.712 (2014).

²⁵¹ 933 S.W.2d 591 (Tex. App.-San Antonio 1996, writ denied).

²⁵² *Id.* at 600.

²⁵³ As described by one commentator, “Purchasing a hedge in the futures market acts as an insurance policy on the price of the commodity. The buyer or seller can lock in an acceptable and effective gas cost as protection against fluctuations and unfavorable

Thus, for example, assume that a producer markets the majority of its gas production at market sensitive index prices, but also is a party to long-term, fixed price gas sales contracts covering a smaller percentage of its total production. Such a producer might pursue the following two-pronged hedging strategy. In the first instance (“Swap A”), the producer would enter into a “vanilla” or “fixed-for-floating” swap transaction with respect to a “notional” (hypothetical) volume of gas equal to a percentage of the producer’s estimated future production to be sold at index prices. Pursuant to Swap A, the producer would pay to the swap counterparty an agreed upon index (or “floating”) price (which may or may not be the same index price at which the producer actually sells some or all of its production), and the counterparty would pay to the producer an agreed upon fixed reference price for the same notional volume of gas. In the second instance (“Swap B”), the producer would enter into a similar swap transaction with respect to a notional quantity equal to a percentage of the producer’s estimated future production to be sold at fixed prices. In contrast to Swap A, the producer in Swap B is the payor of the agreed upon fixed reference price, and the counterparty is the payor of the agreed upon floating price. In neither case is the swap transaction linked to gas produced from a particular oil and gas lease or gas sold under a particular sales contract. The effect of Swap A is to transform a portion of the producer’s anticipated variable cash flows from index priced gas sales into a fixed stream of revenues.²⁵⁴ In the case of Swap B, the producer’s execution of its long-term, fixed price gas contracts is

shifts in the cash market price. If a buyer or seller fails to hedge against possible adverse price changes, it suffers the same risks associated with the failure to buy liability insurance for its business. An adverse change in the market would be the equivalent to being found liable for negligence and damages. Without the insurance policy the buyer or seller bears the entire burden of the loss.” See McLaurin, *supra* note 34, at G 4.

²⁵⁴ See McLaurin, *supra* note 34, at G-11.

inherently a form of price hedge as to the volumes sold under such contracts. So, the effect of Swap B is to permit the producer to preserve for itself, with respect to a portion of its estimated future fixed price gas portfolio, at least some of the potential price “upside” available in the index price market (while minimizing the corresponding “downside” risk).²⁵⁵

In both cases, the royalty owner is likely to argue that the producer breached the implied covenant to market by securing for itself economic benefits pursuant to the swap transactions that were not shared with the royalty owner. The rationale of the take-or-pay settlement cases suggests, however, that the Texas courts are not likely to rule in favor of the royalty owner in this type of case. Both swaps appear to be purely financial transactions undertaken by the producer outside the context of the oil and gas lease and as to which no oil or gas is produced or sold. The notional volumes of gas on which both swaps are based are fixed when the swaps are entered into, regardless of fluctuations in the volumes of gas actually produced and delivered by the producer from time to time under its gas sale contracts. The producer bears the full economic risk of the swap transactions, including the risk of liability if the producer finds himself “out of the money” at the expiration of the swap agreement.²⁵⁶ Under these circumstances, since the swap transactions are purely financial in nature and do not relate to the actual production or sale of gas, we suggest that the producer owes no obligation to the royalty owner under the implied covenant to market with respect to the swap transactions, and that any economic benefit received by the producer from the swap transactions should not be royalty-bearing.

²⁵⁵ See Hazel, *supra* note 16, at H-5.

²⁵⁶ See F.B. Cochran, *Financing with Oil and Gas Derivatives*, 13TH ANN. ADV. OIL, GAS & MIN. L. COURSE, St. Bar of Texas, Ch. I at I-15, I-16 (1995).

Although there are no Texas cases that deal specifically with this issue, a 1984 federal district court case applying Nevada law, *Candelaria Industries, Inc. v. Occidental Petroleum Corporation*,²⁵⁷ supports this conclusion. In that case, the owners of gold and silver mines hedged their projected silver production prior to the development of the mine at a time when the price of silver was high. When the silver market collapsed, the owners of the mine closed the mine and realized substantial profits on their hedging transactions.²⁵⁸ The court rejected the claims of royalty owners under several mining claims of a right to participate in the gain realized by the mine owners from the hedging transactions. According to the court, the royalty owners were entitled to participate only in profits realized through the actual production of minerals from the property.²⁵⁹

b. Futures Contract. In most cases, futures contracts traded on NYMEX or another commodity exchange are closed out by making an opposite trade on the same exchange, so that the transaction remains financial in character without an obligation to make either physical deliveries or receipts of gas. In that event, the analysis of the royalty owner's right to receive royalty on any economic benefits received by the producer from its futures transaction is the same as that for swap transactions.

If a producer has an open sales position under a futures contract when trading closes for that contract in the month of delivery, however, the producer will be obligated to deliver the requisite volume of gas to a buyer designated by the futures exchange at the applicable hub. The producer delivering the gas will invoice the purchaser designated by the exchange for payment based upon the applicable

settlement price for the delivery month. In that event, the producer would calculate and pay royalty on the volumes of gas delivered pursuant to the futures contract in accordance with the provisions of the applicable oil and gas lease.

E. Market Value.

1. The Vela Decision.

The royalty disputes at the center of the two seminal Texas cases defining the concept of market value – *Texas Oil & Gas Corp. v. Vela*,²⁶⁰ and *Exxon Corp. v. Middleton*²⁶¹ -- arose in similar economic contexts: periods of rising gas prices in which then-current market values frequently exceeded the prices payable under existing long-term gas sale contracts. In *Vela*, for example, the lessees under several mid-1930's oil and gas leases covering lands located in the Lopeno Field in Zapata County contracted in 1934 to sell the gas to a utility for the life of the leases at a fixed price of \$0.035 per Mcf without future escalation. The lessee/sellers then entered into gas purchase contracts with various operators in the field, pursuant to which such parties purchased the operators' gas for resale to the utility for the lives of the leases at a fixed price of \$0.023 per Mcf without escalation. By the early 1960's, the net prices being paid by the purchasers of gas in the Lopeno Field – both interstate pipelines and intrastate pipelines – ranged from \$0.13 to \$0.1724 per Mcf.²⁶²

The leases in *Vela* obligated the lessee to “pay to lessor, as royalty for gas from each well where gas only is found, while the same is being sold or used off the premises, one-eighth of the market price at the wells of the amount so sold or used.”²⁶³ The lessee in *Vela* argued that, because gas

²⁵⁷ 662 F. Supp. 1002 (D. Nev. 1984).

²⁵⁸ *Id.* at 1003.

²⁵⁹ *Id.* at 1004-05.

²⁶⁰ 429 S.W.2d 866 (Tex. 1968).

²⁶¹ 613 S.W.2d 240 (Tex. 1981).

²⁶² 429 S.W.2d at 871.

²⁶³ *Id.* at 868.

produced from the Lopeno Field in the 1930s could not be sold on a day-to-day basis, but could only be marketed under long-term, fixed-price sales contracts, the market price of gas within the meaning of the quoted royalty clause could only be the price contracted for in good faith by the lessees under their long-term contracts.²⁶⁴

The Texas Supreme Court rejected the lessee's position and, in so doing, fired the "shot heard 'round the world" of market-value royalty analysis. Among the fundamental principles established by *Vela* were the following:

- The lessee's royalty obligation must be determined from the terms of the underlying oil and gas leases, which were executed prior to, and were transactions wholly independent of, the lessee's gas sale contracts.²⁶⁵
- With respect to gas "sold or used off the premises," royalty is calculated under the quoted provision based on the prevailing market price of the gas at the time of the sale of the gas to the purchaser thereof.²⁶⁶
- The sale of the gas took place at the time of delivery of the gas to the gas purchaser. Thus, the applicable market price was the prevailing market price at the time of the delivery of the gas to the purchaser, and not at the time of the execution of the sales contract. As stated by the court, "The contract price for which the gas was sold by the lessee is not necessarily the market price within the meaning of the lease."²⁶⁷

- Market price should be established by reference to sales of gas comparable in time, quality, and availability of marketing outlets.²⁶⁸ The mathematical average of all prices prevailing in a field does not necessarily yield the market price at any particular point in time, however.²⁶⁹ Based on the evidence presented, the court upheld the trial court's determination that the market price of the gas during the period in question was \$0.13047 per Mcf.²⁷⁰

In support of its decision, the Texas Supreme Court relied heavily on *Foster v. Atlantic Refining Co.*,²⁷¹ a 1964 Fifth Circuit decision applying Texas law. In *Foster*, the Fifth Circuit, in considering how market value should be determined under a gas royalty clause providing for a 1/8 royalty on gas "produced and saved from said land, the same to be . . . sold at the market price therefor prevailing for the field where produced *when run*"²⁷² (emphasis added), affirmed the district court's judgment and held that the lessee must account to the lessor for royalty on gas production based on the value of the gas when produced and delivered, rather than on the price received by the lessee under its twenty-year-term gas sales contract entered into several years before.²⁷³ In so holding, the court rejected the lessee's defense that it was impossible for the lessee to have included in the gas sales contract, at the time of its execution, price escalation provisions to match prevailing market prices for gas during the life of the contract, stating that "the fact that the ascertainment of future market price may be troublesome or that the royalty provisions are improvident and result

²⁶⁴ *Id.* at 870.

²⁶⁵ *Id.*

²⁶⁶ *Id.* at 871.

²⁶⁷ *Id.*

²⁶⁸ *Id.* at 872.

²⁶⁹ *Id.* at 873.

²⁷⁰ *Id.*

²⁷¹ 329 F.2d 485 (5th Cir. 1964).

²⁷² *Id.* at 488.

²⁷³ *Id.* at 489.

in a financial loss to Atlantic 'is not a web of the Court's weaving."²⁷⁴

It should be noted that *Vela* was a 5-to-4 decision, and the criticism of the majority's opinion, including, in particular, its reliance on *Foster*, is eloquently expressed in Justice Hamilton's dissenting opinion (joined by three other judges). After noting that the lessors and lessees in 1933 knew that gas production could only be marketed under long term or life-of-lease sales contracts similar to the contracts in controversy, Justice Hamilton stated:

The problem before us is by no means the problem that the 5th Circuit had in the *Foster* case. In that case the lessee bound itself to pay the prevailing 'market price' in the field when the gas was delivered. In the case before us the lessee bound itself to pay "market price" for gas sold (necessarily sold under long-term contracts). The lessee did not agree to pay the "market price" prevailing in the field at the time of delivery, but agreed to pay the "market price" of gas sold; that is, sold under long-term contract at a price determined as of the time the contract was made. If the parties understand that the price for which gas was to be sold under long-term contracts had to be determined as of time of making the contract, is it not reasonable to say that they understood that market price was to be determined as of the same time?²⁷⁵

²⁷⁴ *Id.* at 490.

²⁷⁵ *Vela*, 429 S.W.2d 866, 879-80 (Hamilton, J. dissenting).

2. From *Vela* to *Middleton*

Thirteen years elapsed between *Vela* and the Texas Supreme Court's 1981 decision in *Middleton*. In the interim, *Vela* generated extensive legal commentary, much of it negative;²⁷⁶ the revolution in the regulatory and commercial structures of U.S. gas marketing began;²⁷⁷ the Texas courts addressed some of the many of the secondary issues raised by *Vela*, including, in particular, the effect of Federal wellhead price regulation on the determination of market value; and courts in other states began to address and resolve on their own the market value issues addressed in *Vela*.

a. Regulated Prices and Market Value.

A key issue in the analysis of market value royalty during this period was the effect of federal regulation of wellhead gas prices under the NGA and, later, the NGPA on the determination of market value for gas royalty purposes. If the market value of gas sold in the interstate market were determined by reference to applicable FPC rates or NGPA maximum lawful prices, rather than by reference to the value of the gas in a hypothetical market free of regulation, the royalty exposure under the *Vela* analysis of lessees selling gas in the interstate market would be reduced or at least capped.

Although the market value evidence presented in *Vela* included testimony about the prices being paid under gas sale

²⁷⁶ E.g., Joseph W. Morris, *The Gas Royalty Clause — What Is Market Value?*, 25TH ANN. INST. ON OIL & GAS L. & TAX'N 63, at 75 (1974) (hereinafter, "Morris") (stating that *Vela* "stands alone in its construction of this [market price] language and it should not be followed by the courts in other jurisdictions."). See also Frank G. Harmon, *Vela Today: Market Value Royalty Problems*, 27 OIL & GAS TAX Q. 185 (1978); William S. Hayes, *Vela: Legacy of Conflict Over Determination of Market Value for Royalties*, 11 ST. MARY'S L.J. 502 (1979); Raymond B. Kelly, III, *What Price, Gas?*, 7 ST. MARY'S L.J. 333 (1975).

²⁷⁷ See notes 18 through 23 and accompanying text, *supra*.

contracts in both the interstate and intrastate markets, the Texas Supreme Court was, somewhat surprisingly, otherwise silent on this issue.²⁷⁸ The federal courts, however, had been considering the impact on the determination of “market value” or “market price” of the FPC’s NGA jurisdiction over wellhead sales of gas in the interstate market for several years.²⁷⁹

²⁷⁸ *Texas Oil & Gas Corp. v. Vela*, 429 S.W.2d 866, 873 (Tex. 1968). See, e.g., *Domatti v. Exxon Corp.*, 494 F. Supp. 306, 312 (W.D. La. 1980) (court noted that *Vela* did not address the problem of how the market value of gas sold in the interstate market was to be determined); *Hemus & Co. v. Hawkins*, 452 F. Supp. 861, 862 (S.D. Tex. 1978) (court concluded that *Vela* “does not really address...what sales are really comparable?”).

²⁷⁹ Initially, the question whether a producer, whose gas sales were price-regulated by the FPC under the NGA, could be required to pay royalty under a market value royalty clause on a price basis greater than the regulated rate received by the producer from an interstate pipeline was analyzed based on whether the producer’s royalty obligation constituted a sale of gas in interstate commerce by the royalty owner subject to the primary jurisdiction of the FPC under the NGA. In *J. M. Huber Corp. v. Denman*, 367 F.2d 104, 121 (5th Cir. 1966) and *Weymouth v. Colorado Interstate Gas Co.*, 367 F.2d 84, 103 (5th Cir. 1966), both decided on the same day in 1966, the Fifth Circuit deferred the determination of the actual “market prices” until the parties obtained a ruling from the FPC concerning whether, inter alia, (i) the FPC had jurisdiction over the payment of royalties for gas sold for resale in interstate commerce and (ii) a royalty owner’s transaction with its lessee was a sale of gas subject to FPC jurisdiction under the NGA when incident to a sale for resale in interstate commerce. Judge Brown, writing for the Fifth Circuit, criticized as inadequate the district court’s definition of “market price” as “that price which a willing buyer would pay and a willing seller would take, after fair negotiation, with neither party acting under compulsion”, stating: “So this ‘free’, ‘willing’ buyer is not so ‘free.’ Nor is his counterpart, the seller. Nor is the commodity. Nor is the business. Nor is the sale. The test in capsulated form is, then, what would a willing seller and a willing buyer in a business which subjects them and the commodity to restriction and regulation, including a commitment for a long period of time, agree to take and pay with a reasonable expectation that the FPC would approve the price (and price changes) and other terms and then issue the necessary certificate of public convenience and necessity.” *Id.* at 90. This line of inquiry ended,

In short order, there followed a series of federal court cases, most of which applied Texas law, in which the courts concluded that sales of gas in the intrastate market were not “comparable sales” for purposes of determining the market value of gas sold in the interstate market and that, indeed, the market value of interstate gas must be determined by reference to gas of the same regulatory classification and vintage under applicable FPC regulations and orders.²⁸⁰ Consistent with these results, after the enactment of the NGPA, the federal courts consistently held that the market value of gas subject to NGPA maximum lawful prices may not exceed the applicable maximum lawful price under the NGPA.²⁸¹ The leading Texas case on this point is the Texas Supreme Court’s decision in *First National Bank of Weatherford v. Exxon Corporation*²⁸² (“*Weatherford*”), decided in

mercifully, when, in *Mobil Oil Corp. v. Federal Power Comm’n*, 463 F.2d 256, 258 (D.C. Cir. 1971), *cert. denied*, 406 U.S. 976 (1972), the D.C. Circuit held that the FPC did not have jurisdiction under the NGA over the payment of gas royalties under a typical oil and gas lease. In so holding, the D.C. Circuit specifically overruled FPC Opinion 562, 42 F.P.C. 164, in which the FPC, on petition from the royalty owners in *Huber*, had declared that the royalty provisions of oil and gas leases constituted sales of natural gas for resale in interstate commerce subject to the provisions of the NGA.

²⁸⁰ *Kingery v. Continental Oil Co.*, 626 F.2d 1261, 1264 (5th Cir. 1980), *cert. denied*, 454 U.S. 1148 (1982) (the Fifth Circuit held that “where the gas has been irrevocably dedicated to the interstate market, it follows inexorably that the only comparable sales to be used in determining the market value of such gas are sales on the interstate market”); *Domatti v. Exxon Corp.*, 494 F. Supp. 306, 314 (W.D. La. 1980); *Hemus & Co. v. Hawkins*, 42 F. Supp. 861, 862 (S.D. Tex. 1978). See also *Burns v. Exxon Corp.*, 158 F.3d 336, 342 (5th Cir. 1998). *But see Sowell v. Natural Gas Pipeline Co. of America*, 789 F.2d 1151, 1154-55 (5th Cir. 1986) (court concluded that, under the “market value” royalty provisions in controversy, the lessor was entitled to royalty based on the average market price of all gas sold, whether in the interstate or intrastate markets, in a six county area).

²⁸¹ *Bowers v. Phillips Petroleum Co.*, 692 F.2d 1015, 1021 (5th Cir. 1982); *Flowers v. Diamond Shamrock Corp.*, 693 F.2d 1146, 1153 (5th Cir. 1982).

²⁸² 622 S.W.2d 80 (Tex. 1980).

1981 shortly after *Middleton*. *Weatherford* will be discussed in more detail as part of the *Middleton* analysis below.

b. Market Value in Other States. In an excellent 1974 paper appearing in the proceedings of the Southwestern Legal Foundation's Institute on Oil and Gas Law and Taxation, the distinguished jurist Judge Joseph W. Morris argued that *Vela* stood "alone in its construction of this [market price] language" in the royalty clause in controversy in *Vela* and "should not be followed by the courts in other jurisdictions."²⁸³ Beginning in the late 1970s, however, state supreme courts in Kansas,²⁸⁴ Montana,²⁸⁵ West Virginia,²⁸⁶ and North Dakota,²⁸⁷ as well as the Fifth Circuit applying Mississippi law,²⁸⁸ adopted the reasoning in *Vela* and held that, under typical market value royalty clauses, "market value" or "market price" refer to current market value or market price at the time gas is produced.

The Oklahoma Supreme Court, on the other hand, in *Tara Petroleum Corp. v. Hughey*,²⁸⁹

²⁸³ Morris, *supra* note 276, at 75.

²⁸⁴ *Holmes v. Kewanee Oil Co.*, 233 Kan. 544, 664 P.2d 1335 (Kan. 1983) ; *Matzen v. Cities Service Oil Co.*, 233 Kan. 337, 667 P.2d 337 (Kan. 1983); *Lightcap v. Mobil Oil Corp.*, 221 Kan. 448, 562 P.2d 1 (Kan. 1977).

²⁸⁵ *Montana Power Co. v. Kravik*, 179 Mont. 87, 586 P.2d. 298 (Mont. 1978), *on subsequent appeal*, 189 Mont. 369, 616 P.2d 321 (Mont. 1980).

²⁸⁶ *Teavee Oil & Gas Inc. v. Hardesty*, 171 W.Va. 123, 297 S.E.2d 898 (W. Va. 1982) (court held that, for purposes of the West Virginia business and occupation tax based on fair market value of gas, current market prices at the time of production should be utilized).

²⁸⁷ *Amerada Hess Corp. v. Conrad*, 410 N.W. 124, 130 (N.D. 1987) (North Dakota gross production tax is measured by "the current market value of the gas at the time it is produced").

²⁸⁸ *Piney Woods Country Life School v. Shell Oil Co.*, 726 F.2d 225 (5th Cir. 1984), *cert. denied*, 471 U.S. 1005 (1985).

²⁸⁹ 1981 Okla. 65, 630 P.2d 1269, 1272-74 (Okla. 1981).

expressly rejected the *Vela* reasoning and held that the phrase "market price at the well" in the oil and gas lease in controversy did not refer to current market value, but rather to the price received by the lessee under its long-term gas sale contract. The court's reasoning was similar the argument made by Justice Hamilton in his dissent in *Vela*.²⁹⁰ Similar positions were taken by the courts in Louisiana²⁹¹ and Arkansas.²⁹²

3. The *Middleton* Decision.

By 1981, the Texas Supreme Court appears to have determined it was time to reaffirm, as well as to elaborate upon and clarify, its holding in *Vela*, and it chose the appeal of the Houston Court of Civil Appeals (14th District) decision in *Exxon Corp. v. Middleton*²⁹³ as the vehicle for doing so.

Like *Vela*, the lessees in *Middleton* entered into several oil and gas leases during the 1930s, this time in the Anahuac Field in Chambers County, Texas. The leases in controversy all contained the *Middleton* Lease Royalty Clause quoted above in Section III of this paper.²⁹⁴ During 1973 through 1975, the period complained of by the royalty owner/plaintiffs, some of the gas produced by defendant Exxon was processed at Exxon's Anahuac Gas Plant in

²⁹⁰ See *Texas Oil & Gas Corp. v. Vela*, 429 S.W.2d 866, 879-80 (Tex. 1968) (Hamilton, J., dissenting).

²⁹¹ *Henry v. Ballard & Cordell Corp.*, 418 So. 2d 1334 (La. 1982). *But see Shell Oil Co. v. Williams*, 428 So. 2d 798, 801-02 (La. 1983) (in a case in which the parties stipulated that, under the leases in controversy, the terms "market price" and "market rate" refer to current market value, the court held that the current market value of gas dedicated to the interstate market was to be determined by reference to comparable sales in the interstate market, and not higher, unregulated intrastate sales).

²⁹² *Hillard v. Stephens*, 276 Ark. 545, 637 S.W.2d 581 (1982). *Accord, Taylor v. Arkansas Louisiana Gas Co.*, 604 F. Supp. 779 (W.D. Ark. 1985), *aff'd*, 793 F.2d 189 (8th Cir. 1986).

²⁹³ 571 S.W.2d 349 (Tex. Civ. App – Houston [14th Dist.] 1978), *rev'd*, 613 S.W.2d 240 (Tex. 1981).

²⁹⁴ See text accompanying note 42, *supra*.

Chambers County, Texas, which was not located on the leased premises. Exxon delivered the processed gas at the tailgate of its Anahuac Plant under three intrastate sales contracts to, respectively, the City of Anahuac, Houston Pipeline Company, and Exxon Gas System (an intrastate pipeline serving industrial end-users).²⁹⁵ Under its contract with Houston Pipeline, Exxon received a negotiated price. Under its contracts with the City of Anahuac and Exxon Gas System, however, Exxon received its “field price,” a projected, or “forward,” volume-weighted average price determined according to the prices received by twenty-six major pipeline purchasers in Texas Railroad Commission District 3 and seven adjoining counties. In all cases, Exxon paid royalty based on the proceeds it received under its gas sales contracts.²⁹⁶

Exxon argued, *inter alia*, that the gas sold at the tailgate of its Anahuac Plant was sold “at the well,” so that the “amount realized” royalty standard under the leases in controversy was applicable.²⁹⁷ Alternatively, Exxon argued that the royalty clause in *Vela*, which required royalty to be paid on gas “while the same is being sold or used off the premises,” was distinguishable from the quoted royalty provision in the *Middleton* leases, and that under the *Middleton* leases gas was “sold,” for royalty purposes, on the dates of execution of Exxon’s long-term gas sales contracts.²⁹⁸

The Texas Supreme Court’s decision in *Middleton* rejected Exxon’s positions on these points and stated the following principles:

- The obligation to pay royalty on gas does not accrue until there has been both (a) production of gas and (b) the sale or use of the gas produced.

²⁹⁵ *Middleton*, 613 S.W.2d at 241-42.

²⁹⁶ *Middleton*, 571 S.W.2d at 355-56.

²⁹⁷ *Id.* at 242.

²⁹⁸ *Id.* at 244.

In this regard, production of gas does not occur until the physical severance of the gas from the ground,²⁹⁹ and the sale of gas that triggers the obligation to pay royalty does not occur until the physical delivery of the gas to the purchaser thereof.³⁰⁰

- In the phrase “sold or used off the premises,” the words “off the premises” refer to both the sale and the use of gas.³⁰¹ The word “premises” refers to the “leased premises,” or the lands covered by the relevant oil and gas lease.³⁰² Therefore, if gas is delivered for sale within the leased premises, it will be deemed to be sold “at the well” for royalty calculation purposes, but if gas is delivered for sale at a point outside the leased premises, it will be deemed to be sold “off the premises,” even if the sales delivery point is a central delivery point in the field (such as Exxon’s Anahuac Gas Plant).³⁰³
- If gas is “sold or used off the premises,” royalty is calculated based on the market value at the well of the gas so sold or used,

²⁹⁹ *Id.* (citing *Monsanto Co. v. Tyrell*, 537 S.W.2d 135, 137 (Tex. Civ. App. – Houston [14th Dist.] 1976, writ ref’d n.r.e.)).

³⁰⁰ *Id.* at 244-45 (citing *Texas Oil & Gas Corp. v. Vela*, 429 S.W.2d 866, 871 (Tex. 1968)). This result is also consistent with the terms of the Texas Uniform Commercial Code. See TEX. BUS. & COM. CODE ANN. §2.106(a) (a “sale” consists of the passing of title to the buyer for a price) and §2.107(a) (Tex. U.C.C.) (West 2014) (a contract for the sale of minerals or the like, including oil and gas, is a contract for the sale of goods subject to Chapter 2 of the Texas U.C.C. if the minerals are to be severed by the seller; until severance, however, a purported present sale of such minerals that is *not* effective as a transfer of an interest in land is effective only as a contract to sell).

³⁰¹ *Middleton*, 613 S.W.2d at 243.

³⁰² *Id.* at 242.

³⁰³ *Id.* at 243.

determined at the time of delivery of the gas to the purchaser thereof.³⁰⁴

- Market value at the well is a hypothetical concept — the price property would bring when it is offered for sale by one who desires, but is not obligated, to sell and is bought by one who is under no necessity of buying it. To determine the market value of gas, the gas should be valued as though it is free and available for sale.³⁰⁵
- The preferred method of establishing market value is by evidence of comparable sales — i.e., sales comparable in time, quality (including regulatory character), quantity, and availability of markets.³⁰⁶

The court also made several significant pronouncements about the nature and effect of division orders, which will be discussed later in this paper.

4. Comparable Sales and the Regulatory Character of Gas.

Middleton also elaborated upon the concept of “comparable sales” established in *Vela* as the basis for determining market value. According to the Texas Supreme Court in *Middleton*:

Sales comparable in time occur under contracts executed contemporaneously with the sale of the gas in question. Sales comparable in quality are those of similar physical properties such as sweet, sour, or casinghead

gas. Quality also involves the legal characteristics of the gas; that is, whether it is sold in a regulated or unregulated market, or in one particular category of a regulated market. Sales comparable in quantity are those of similar volumes to the gas in question. To be comparable, the sales must be made from an area with marketing outlets similar to the gas in question. . . . Comparable sales should be drawn from a relevant market. . . .³⁰⁷

The court’s statement regarding gas quality involving not only the physical, but the legal, characteristics of the gas was the first recognition by the Texas courts of the impact of federal regulation of wellhead gas prices on the determination of market value, a subject that had already received extensive attention by the federal courts.³⁰⁸ Unlike the prior federal court cases, however, the issue of federal wellhead price regulation was not the central issue in *Middleton*. In *Middleton*, Exxon appears not to have argued in favor of a specific contract price as the measure of market value, but rather that its method of calculating market value, which produced a lower price basis for royalty calculation purposes, was more accurate than the plaintiffs’.³⁰⁹ The plaintiffs’ expert reviewed over 30,000 monthly gas tax reports filed with the Comptroller of Public Accounts covering gas sales in a market area consisting of Railroad Commission Districts 2, 3, and 4, and then arrived at his opinion regarding market value by calculating the arithmetic average of the three highest prices paid in

³⁰⁴ *Id.* at 245, citing *Texas Oil & Gas Corp. v. Vela*, 429 S.W.2d 866, 871 (Tex. 1968).

³⁰⁵ *Id.* at 246.

³⁰⁶ *Id.*, citing *Texas Oil & Gas Corp. v. Vela*, 429 S.W.2d 866, 872 (Tex. 1968).

³⁰⁷ *Id.* at 246-47.

³⁰⁸ See text accompanying notes 280 and 281, *supra*.

³⁰⁹ *Middleton*, 613 S.W.2d at 246. See Watt, Ramos, and Beckworth, *supra* note 2, at 10.

such market area during each calendar quarter under review. Exxon's expert testified that Exxon's "field price" for the Anahuac Field (calculated as the total price paid for one month out of each calendar quarter for gas delivered to major purchasers in Railroad Commission District 3 and the seven surrounding counties, divided by the total volume of such gas delivered for sale) constituted the market value.

The trial court accepted the plaintiffs' expert opinion on market value, concluding that Exxon's "field price" did not satisfy the "comparability test" because it included both interstate and intrastate sales while all of the gas in controversy was sold in the intrastate market.³¹⁰ Although the court of civil appeals found fault with both expert opinions,³¹¹ the Texas Supreme Court ultimately upheld the trial court's finding.³¹² In so holding, the court stated: "Exxon's field price . . . includes interstate sales. Intrastate and interstate gas prices are not comparable in quality. They are conceptually and legally different While this evidence may be admissible, such evidence does not bind the fact finder as a matter of law in its determination of market value."³¹³

³¹⁰ *Middleton*, 613 S.W.2d at 245-46.

³¹¹ *Id.* at 246. Among other issues regarding the plaintiffs' expert's testimony, the court of civil appeals objected to the plaintiffs' expert's failures to (a) designate the Anahuac Field as the relevant market area, (b) calculate a mathematical average of all prices paid in the Anahuac Field, and (c) corroborate such mathematical average price with comparable sales in the field. *Id.*

³¹² *Id.* at 249. In particular, the Texas Supreme Court specifically rejected the court of civil appeals' objection to the failure by the plaintiffs' expert to calculate a mathematical average of the price paid in the Anahuac Field. Citing *Vela*, the court reaffirmed that "a mathematical average of all prices paid in the field is 'not a final answer to the difficult problem of determining market value at any particular time.'" *Id.* at 248.

³¹³ *Id.*

The last sentence of the quoted language suggests that, in a case involving the determination of the market value of gas sold in the intrastate market, the requirement of comparability of legal or regulatory characteristics goes not so much to the admissibility of evidence of regulated interstate gas prices, but to the weight that the fact finder may choose to give to that evidence. The Texas Supreme Court took a more definitive stance on this issue in *First National Bank of Weatherford v. Exxon Corp.*,³¹⁴ decided five months after *Middleton*. In *Weatherford*, the court addressed directly the question whether gas sales in the intrastate market constitute comparable sales for purposes of determining the value of gas dedicated to the interstate market.³¹⁵ After citing *Middleton* as the controlling authority, the court quoted the second and third sentences, but not the last sentence, of the language quoted above and stated, "We hold that intrastate sales of gas are not comparable to interstate sales regulated by the Federal Power Commission."³¹⁶

5. Does the Elevator Also Go Down?

Vela and *Middleton* teach us that, in a period of rising gas prices, market value royalty provisions may work to the advantage of royalty owners and the disadvantage of producers, requiring producers to account for royalties on a price basis higher than that received by the producer under the applicable gas sale contract.

Does the same analysis apply when the lessee sells gas for more than the market value of such gas under a long term sales contract? In *Yzaguirre v. KCS Resources, Inc.*,³¹⁷ the Texas Supreme Court answered

³¹⁴ 622 S.W.2d 80 (Tex. 1981).

³¹⁵ *Id.*

³¹⁶ *Id.* at 82.

³¹⁷ 53 S.W.3d 368 (Tex. 2001). In an unpublished opinion decided two years earlier, the Dallas Court of Appeals had reached the same decision based on

“yes.” In *Yzaguirre*, the leases in controversy, executed in 1973, contained *Middleton* Lease Royalty Clauses. In 1979, the lessees entered into a 20-year gas purchase contract with Tennessee Gas Pipeline Co., under which Tennessee agreed to purchase gas produced from the leases at a fixed price subject to automatic price escalations (the “Tennessee Contract”). Gas produced from the leases was processed several miles from the leased premises and sold to Tennessee at the tailgate of the plant. As such, the gas was “sold or used off the leased premises,” and royalty was, therefore, payable based on the market value standard. By the 1990s, when substantial production from the leases was obtained as the result of the development of the Bob West field, the automatic price escalations in the Tennessee Contract had caused the price paid for gas sold thereunder to far exceed the market value of the gas.³¹⁸

The lessees filed suit seeking a declaratory judgment that royalty on production from the leases was payable based on the market value of such gas, rather than the higher price paid under the Tennessee Contract. The trial court rendered judgment in favor of the lessees, and the court of appeals and the Texas Supreme Court affirmed. According to the Texas Supreme Court, citing *Vela* as controlling precedent:

The parties to these leases, in unambiguous terms, based the royalty on the amount realized for gas sales at the well and on market value for sales that occurred

off the premises. This clearly means the prevailing market price at the time of the sale or use. Because the *Vela* lease’s plain terms specified a market price royalty, we rejected the lessee’s argument that the “market price of gas within the meaning of the lease is the price contracted for in good faith by the lessee in pursuance of its duty to market gas from the premises.” Instead, we held that the plain terms of the lease required the lessee to pay a market value royalty even though the lessee received less than market value under its long term sales contract. The same plain terms that fixed the lessee’s duty to pay royalty also defined the benefit the lessor is entitled to receive. Thus under the leases, *Yzaguirre* and the other royalty owners are entitled to a market value royalty, not an amount realized royalty.³¹⁹

Two years later, the Texas Supreme Court leaned heavily on its decision in *Yzaguirre* in *Union Pacific Resources Group, Inc. v. Hankins*,³²⁰ a class action suit brought by royalty owners alleging that the lessee, which sold gas produced from the leases in controversy to affiliates at certain index prices, had improperly paid royalties based on the index prices used in the inter-affiliate

similar facts in *De los Santos v. Coastal Oil & Gas Corporation*, 1999 WL 619639 (Tex. App. – Dallas) (not designated for publication).

³¹⁸ *Id.* at 371. Indeed, Tennessee sought, unsuccessfully, a declaratory judgment that the gas contract did not obligate it to purchase all of the gas produced from the leases at the escalated price provided for therein. See *The Lenape Resources Corp. v. Tennessee Gas Pipeline Co.*, 925 S.W.2d 565 (Tex. 1996).

³¹⁹ 53 S.W.3d 368 at 373-74, citing *Texas Oil and Gas Corp. v. Vela*, 429 S.W.2d 866, 870-71 (Tex. 1968), and *Amoco Prod. Co. v. First Baptist Church of Pyote*, 611 S.W.2d 610 (Tex. 1980). *Accord*, *Piney Woods Country Life School v. Shell Oil Co.*, 726 F.2d 225, 234 (5th Cir. 1984), *cert. denied*, 471 U.S. 1005 (1985) (“If the price of gas declines, a market value royalty clause would benefit a lessee who has contracted to sell at a favorable price.”)

³²⁰ 111 S.W.3d 69, 71 (Tex. 2003).

sale, rather than the higher prices received by the lessee's affiliates on the resale of the gas. In concluding that the plaintiffs' class failed to satisfy the "commonality" requirement for class certification under Texas Rule of Civil Procedure 42,³²¹ the supreme court rejected the plaintiffs' argument that, regardless of whether a "market value" or "amount realized" royalty standard was applicable under a particular lease, royalty was payable based on the resale proceeds received by the lessee's affiliates.³²² According to the court:

Could the trial court . . . infer that the third party sale price represented both market value and the best price reasonably attainable? No, because the marketing affiliates may have been able to receive a price higher than market value, either through a long-term contract as in *Yzaguirre* or simply through extraordinary negotiation and sales efforts that exceeded the results reasonably obtainable by an ordinary lessee. Under this scenario, the proceeds owner would be entitled to share in the lessee's good fortune, while the market-value owners would not be. [Citations omitted] Conversely, the third-party sale price might conceivably be lower than market value, in which case the proceeds owners would receive less than the market-value owners . . . Further analysis would be needed to determine whether market-

value owners were indeed paid market value.³²³

As one might suspect, the Texas Supreme Court's decisions in *Yzaguirre* and *Hankins* were roundly criticized by royalty owners and their lawyers.³²⁴ As a general proposition, however, the results in *Yzaguirre* and *Hankins* seem to represent the logical extension of the market value analysis of *Vela* and *Middleton*. If the market value standard calls for the payment of royalty based upon current comparable sales of gas utilizing the model of the willing buyer/willing seller, without reference to the proceeds actually received by the producer under the applicable gas sale contract, then in a period of declining gas prices, the producer who contracts for the sale of its gas at a price in excess of market value should be entitled to retain the full amount of that premium.³²⁵ Stated differently, under the *Vela-Middleton* market value formulation, the producer bears the commodity price risk of the gas for royalty purposes during periods of increasing prices, and the royalty owner bears this commodity price risk during periods of declining prices.³²⁶

³²³ *Id.*

³²⁴ See, e.g., Watt, Ramos, and Beckworth, *supra* note 2, at 11, 12, 15-18; Garcia, *supra* note 2, at 7.

³²⁵ See Allen D. Cummings, Susan Richardson, and Lisa Vaughan, *Litigating Gas Royalty Cases*, 19 OIL, GAS & MIN. L. SECTION REPORT, St. Bar of Tex., No. 3, at 25, 26 (1995) (hereinafter, "Cummings, Richardson and Vaughan"); Pearson and Watt, *supra* note 3, at 14-26, 14-27; David E. Pierce, *Royalty Valuation Principles in a Changing Gas Market*, 11TH ANN. ADV. OIL, GAS & MIN. L. COURSE, St. Bar of Tex., Paper E, at E-12, E-13 (1993); John S. Lowe, *Current Lease and Royalty Problems in the Gas Industry*, 23 TULSA L. J. 547 (1988).

³²⁶ Messrs. Watt, Ramos, and Beckworth argue that this analysis is flawed when applied to the facts in *Yzaguirre* because (a) the lessee bore no commodity price risk under the Tennessee Contract since the contract provided only for escalations, and no reductions, of the gas price paid thereunder and (b) the Tennessee Contract expressly indemnified the lessee against *Vela*-type royalty risk. See Watt, Ramos, and Beckworth, *supra* note 2, at 12.

³²¹ Tex. R. Civ. P. 42(b).

³²² 111 S.W.3d at 76.

6. Market Value and the Implied Covenant to Market.

In *Cabot Corp. v. Brown*,³²⁷ the Texas Supreme Court characterized the implied covenant to market as being two-pronged: the lessee must (a) market the production with due diligence and (b) obtain the best price reasonably possible.³²⁸ In *Cabot*, decided six years after *Middleton*, the Texas Supreme Court stated, in dictum, that under a gas royalty clause providing for royalties based on market value, the lessee has an obligation to obtain the best current price reasonably available.³²⁹

In *Yzaguirre v. KCS Resources, Inc.*³³⁰, however, after concluding that the

plaintiff/royalty owners were entitled, under the terms of the applicable lease royalty clause, to be paid royalty based upon the lower current market value of the gas rather than the higher sale price received by the lessee under the Tennessee Contract,³³¹ the Texas Supreme Court rejected the royalty owners' argument that the lessee's failure to pay royalty based on the Tennessee Contract proceeds constituted a breach of the implied covenant to market the gas.³³² After noting that implied covenants do not come into existence when the lease expressly covers the subject matter of the implied covenant, the court stated:

In this case, the parties entered into a lease requiring a market value royalty. Because the lease provides an objective basis for calculating royalties that is independent of the price the lessee actually obtains, the lessor does not need the protection of an implied covenant. Depending on future market behavior, this may be financially beneficial to the lessor, as it was in *Vela*, or it may be less advantageous, as here. In either event, the parties received the benefit of their bargain. . . . [U]nder these circumstances, we do not believe the *Cabot* dicta should override our decisions in *Vela*, *Pyote*, and *Middleton*.³³³

³²⁷ 754 S.W.2d 104 (Tex. 1987).

³²⁸ *Id.* at 106. The implied covenant to market is clearly applicable to royalty on gas production calculated based on the amount realized by the lessee from the sale of such production, although the implied covenant does not imply a duty to sell gas at market value. *E.g.*, *Amoco Prod. Co. v. First Baptist Church*, 579 S.W.2d 280, 287 (Tex. Civ. App. – El Paso 1979), *writ ref'd n.r.e. per curiam*, 611 S.W.2d 610 (Tex. 1980).

³²⁹ 754 S.W.2d at 106. In *Cabot*, the lessee under a lease providing for the payment of royalty based on the market value of gas production at the well actually paid royalty on such gas production, which was dedicated to and sold in interstate commerce under the NGA, pursuant to division orders executed by the royalty owner which obligated the lessee to pay royalty based on the applicable FPC ceiling rate. *Id.* at 105. The supreme court held that, until the division orders, which established a royalty payment standard different from that provided for in the lease, were revoked, the plaintiffs were precluded from asserting a claim for damages under the implied covenant to market based on the lessee's failure to seek an abandonment of the gas under the NGA so that it could be sold in the higher-priced intrastate market. *Id.* at 107 (citing *Middleton*). The division orders were deemed revoked when the lessee was served with process in this litigation, and the court remanded the case to the trial court to permit the royalty owner to establish its damages, if any, for the period after the division orders were revoked. *Id.* at 108. Because the quoted language relating to the implied covenant to market was not central to the court's decision, it is generally regarded as dictum.

³³⁰ 53 S.W.3d 368 (Tex. 2001).

³³¹ *Id.* at 372-73.

³³² *Id.* at 373-74.

³³³ *Id.* This result had been called for by numerous commentators for some time. *See, e.g.*, Cummings, Richardson, & Vaughan, *supra* note 325, at 25, 26; McCartney, *supra* note 65, at K-21; Miller, *supra* note 2, at K-10, K-11.

Yzaguirre's treatment of the *Cabot* dictum has been criticized by some because, to the extent that the court in *Cabot* remanded the case to the trial court to give the plaintiffs the opportunity to recover on their implied covenant claim for the period after the division orders had been revoked, the plaintiffs' implied covenant claims had been preserved, and because the court did not expressly overrule the quoted dictum from *Cabot*.³³⁴ While there may be merit to these criticisms, it seems that *Yzaguirre*'s statement that "we do not believe the *Cabot* dicta should override our decisions in *Vela*, *Pyote*, and *Middleton*"³³⁵ clearly indicates that the quoted dictum from *Cabot* is no longer the law in Texas and that the implied covenant to market does not obligate the lessee to obtain the best current price reasonably available if a market value royalty standard is in effect.³³⁶

This holding has been followed in a number of subsequent cases and played a particularly significant role in several of the class action lawsuits filed by royalty owners in Texas during the late 1990s and early 2000s. One of the requirements for certifying a class in a class action brought in Texas is that there be "commonality" among the members of the proposed class – that is, there must be questions of law or fact common to the class.³³⁷ Because most of these cases involved royalty owner claims arising under both market value and amount realized royalty provisions, the applicability,

³³⁴ See Watt, Ramos and Beckworth, *supra* note 2, at 21, 22.

³³⁵ *Yzaguirre v. KCS Res., Inc.*, 53 S.W.3d 368, 375 (Tex. 2001).

³³⁶ The holding in *Yzaguirre* does not, however, necessarily affect the lessee's obligation to market production with due diligence. In addition, in a footnote, the court in *Yzaguirre* suggested that a royalty owner under a market value royalty standard might have a claim under the implied covenant to market if the lessee intentionally sold gas off the leased premises in order to reduce the amount payable to the royalty owner. *Id.* at 375 n.3. See Watt, Ramos and Beckworth, *supra* note 2, at 22.

³³⁷ Tex. R. Civ. P. 42(a), 42(b).

as the result of *Yzaguirre*, of the implied covenant to market only to royalty owners claiming under amount realized royalty provisions has been held to be sufficient to defeat class certification due to lack of "commonality" among the members of the proposed class.³³⁸

7. Proving Market Value: Comparable Sales v. Netback Method (Herein of Heritage Resources).

Regardless of whether one agrees or disagrees with the Texas Supreme Court's decisions in *Vela*, *Middleton*, *Yzaguirre*, and *Hankins*, they appear to establish a reasonably well defined analytical framework for the determination of market value royalty that possesses a certain internal logic.³³⁹ That framework was

³³⁸ For example, in *Union Pacific Resources Group, Inc. v. Hankins*, 111 S.W.3d 69 (Tex. 2003), the Texas Supreme Court reversed a court of appeals judgment certifying the plaintiff class and held that, "[b]ecause a covenant to obtain the best price reasonably available is implied under Texas law only to proceeds leases, not to market-value leases," the royalty owners had not established "questions of law or fact common to the class" sufficient to support certification. *Id.* at 70. After reviewing the list of common issues developed for the proposed class by the trial court, several of which asked whether the defendants had "breached the implied covenant to reasonably market," the court stated:

Since *Yzaguirre* held that market value leases have no such implied covenant, these questions cannot satisfy the commonality requirement in a class that includes both proceeds leases and market value leases.

Id. at 75.

Accord, *Bowden v. Phillips Petroleum Co.*, 247 S.W.3d 690, 708-709 (Tex. 2008) (with respect to plaintiff/royalty owner "Subclass 3"); *Union Pacific Resources Group, Inc. v. Neinast*, 67 S.W.3d 275 (Tex. App. – Houston [1st Dist.] 2001, *pet. denied*); and *Enron Oil & Gas Co. v. Joffrion*, 116 S.W.3d 215 (Tex. App. – Tyler 2003, *no pet.*); *Stirman v. Exxon Corp.*, 280 F.3d 554, 563 (5th Cir. 2002); *Hunter v. Exxon Corp.*, 2005 WL 357682 (W.D. Tex. 2005). *But see* notes 390 and 391 and accompanying text, *infra*.

³³⁹ There are, of course, numerous distinguished commentators who do not completely share this view.

clearly, although perhaps unintentionally, called into question by the Texas Supreme Court's 1996 decision in *Heritage Resources, Inc. v. NationsBank*,³⁴⁰ the second of the two most significant market value decisions since *Middleton*.

a. Comparable Sales. It seems fair to characterize the core concepts underlying *Vela*, *Middleton*, and *Yzaguirre* as follows: (i) "market value" is defined not by oil and gas industry custom and practice but by the applicable oil and gas lease language; and (ii) the "typical" market value royalty provision calls for the determination of market value based on evidence of comparable sales – sales comparable in time, quality (including regulatory character), quantity, and availability of markets – by expert testimony utilizing the model of the willing seller/willing buyer, which amount may be wholly unrelated to the actual proceeds received by the producer under its gas sale contract.³⁴¹ Once experts are qualified, their testimony is to be considered by the trier of fact, who can determine the weight to be given to the evidence.³⁴²

An interesting issue in this regard is, notwithstanding *Vela*'s admonition that "the contract price for which the gas was sold is not necessarily the market price within the

meaning of the lease,"³⁴³ whether evidence of the price actually paid for the gas in controversy is admissible as one of the "comparable sales" evaluated by the market value expert. In *Vela*³⁴⁴ the defendant's market value expert was permitted to include in his analysis the old, fixed price contracts under which the defendant's gas was being sold, although he ultimately excluded the prices paid under such contracts from his market value calculation because they were "too far out of line."³⁴⁵ In *Middleton*, it is unclear whether the plaintiff's market value expert reviewed the gas sales contracts under which Exxon sold the gas in controversy, although nothing in the Texas Supreme Court's opinion expressly indicates that they were excluded from evidence.

In *Yzaguirre*, on the other hand, the Texas Supreme Court affirmed the trial court's decision to exclude evidence of the price received by the defendant for gas sold under the Tennessee Contract.³⁴⁶ In so holding the court stated:

According to the [Tennessee Contract], Tennessee was obligated to purchase [the defendant's] gas at an ever-escalating price, regardless of its value on the open market. The gas was not free and available for sale, and its price was negotiated

See Watt, *supra* note 2, at 8 ("In reading these cases, one is reminded of the fable of the group of blind men, who each describe an elephant by feeling a different part of its body, with the elephant looking entirely different depending on which body part is being described. Because of this, it is becoming increasingly difficult to rationally or fairly apply these earlier holdings to current disputes. . . ."); Watt, Ramos, and Beckworth, *supra* note 2, at 12-22.

³⁴⁰ 939 S.W.2d 118 (Tex. 1996).

³⁴¹ *Exxon Corp. v. Middleton*, 613 S.W.2d 240, 245-49 (Tex. 1981); *Texas Oil & Gas Corp. v. Vela*, 429 S.W.2d 866, 872-74 (Tex. 1968). *Accord*, *Piney Woods County Life School v. Shell Oil Co.*, 725 F.2d 225, 234 (5th Cir. 1984), *cert. denied*, 471 U.S. 1005 (1985).

³⁴² *Middleton*, 613 S.W.2d at 249.

³⁴³ *Vela*, 429 S.W.2d at 871.

³⁴⁴ In *Vela*, the defendant's expert reviewed all gas sales from the Lopeno Field during the four years prior to the commencement of the *Vela* litigation, determined the arithmetic average of these sales prices, deducted a charge for compression, and determined the market value to be \$0.13047 per Mcf. *Id.* at 872-73. Although the court noted that "the mathematical average of all prices paid in the field is not the final answer" in determining market value, *id.* at 874, the court upheld the expert's finding. *Id.*

³⁴⁵ *Id.* at 873.

³⁴⁶ *Yzaguirre v. KCS Res., Inc.*, 53 S.W.3d 368, 374-75 (Tex. 2001).

in 1979, not contemporaneously with the deliveries. Under these circumstances, the [Tennessee Contract] price was not evidence of market value, and the trial judge properly excluded it.³⁴⁷

As before, this holding has been roundly criticized by royalty owners and their counsel, and with some justification. At a minimum, it seems that evidence of the actual sales price paid for the gas in controversy is at least relevant in a market value case and should be admissible. The lesson of these cases may be that the older the vintage of the gas sales contract, the less relevant the price paid under such contract will be in determining current market value. That issue relates to the weight to be given to the evidence, however, and not its admissibility. The court in *Vela* appears to have had the better approach when it admitted evidence of the actual sales prices paid for the gas in controversy but upheld the expert's decision to exclude such sales prices from his calculation of market value.³⁴⁸

b. Net-Back Method. Establishing market value based on evidence of comparable sales can make for expensive litigation. In addition, it may be difficult, in some circumstances, to develop sufficient evidence of comparable sales to support a

³⁴⁷ *Id.*, citing *Texas Oil & Gas Corp. v. Vela*, 429 S.W.2d 866, 871 (Tex. 1968), and *Exxon Corp. v. Middleton*, 613 S.W.2d 240, 244-46 (Tex. 1981).

³⁴⁸ See Garcia, *supra* note 2, at 10, 11; Watt, Ramos and Beckworth, *supra* note 2, at 15-18. In some cases, the courts have honored the applicable sales price as the proper measure of current market value. See, e.g., *Piney Woods Country Life School v. Shell Oil Co.*, 905 F.2d 840, 850 (5th Cir. 1990) (on appeal of the district court's judgment following the Fifth Circuit's remand of the case pursuant to its 1984 decision, the court held that the evidence sustained the district court's finding that the applicable contract price represented the fair market value of the gas in controversy); *Maddox v. Texas Co.*, 150 F. Supp. 175, 180 (E.D. Tex. 1957).

determination of market value at the well. Is there, then, a permissible alternative method of determining market value? In *Heritage Resources, Inc. v. NationsBank*,³⁴⁹ the Texas Supreme Court answered "yes" to this question and endorsed the "work-back" or "net-back" valuation method.³⁵⁰

In *Heritage Resources*, although the royalty provisions in the leases in controversy each differed in certain respects, all of the royalty provisions required royalty to be paid based upon the market value at the well of gas produced or produced and sold from the leased premises, subject, however, in each case to the following proviso:

³⁴⁹ 939 S.W.2d 118 (Tex. 1996).

³⁵⁰ *Heritage Resources* is not the first Texas case to define market value by reference to a net-back methodology. In *Texas Oil & Gas Corp. v. Hagen*, 683 S.W.2d 24 (Tex. Civ. App. – Texarkana 1984), *aff'd in part and rev'd in part*, 31 Tex. Sup. Ct. J. 140 (Tex. 1987), *jdgmt and op. of Tex. Sup. withdrawn, jdgmt of Tex. Civ. App. set aside, motion for reh. and cause dismissed as moot*, 760 S.W.2d 960 (Tex. 1988), the Texarkana Court of Civil Appeals held that market value at the well is market value of the gas where sold, less reasonable and necessary transportation and processing costs. 683 S.W.2d at 28. See also *Phillips Petroleum Co. v. Bynum*, 155 F.2d 196, 198 (5th Cir. 1946) (applying Texas law, held that in the absence of available evidence of market price at the well, it "would seem appropriate" to look at the market price paid by purchasers in the area of the point of sale, and then to deduct transportation costs.) The "work-back" or "net-back" method of calculating market value has been endorsed by the courts in other states. See *Piney Woods County Life School v. Shell Oil Co.*, 726 F.2d 225, 239 (5th Cir. 1984), *cert. denied*, 471 U.S. 1005 (1985); *Ashland Oil, Inc. v. Phillips Petroleum Co.*, 554 F.2d 381, 387 (10th Cir. 1977), *on remand*, 463 F. Supp. 619 (N.D. Okla. 1978), *aff'd in part and rev'd in part*, 607 F.2d 335, 336 (10th Cir. 1979), *cert. denied*, 446 U.S. 936 (1980) (judgment of trial court set aside based upon trial court's failure to employ the work-back method of calculating the value of helium for royalty purposes); *Montana Power Co. v. Kravik*, 586 P.2d 298, 303 (Mont. 1978) (court approved use of work-back method of calculating market value in the absence of comparable sale information, but stated that "[t]his is the least desirable method of determining market price"). See WILLIAMS & MEYERS, *supra* note 59, §645.2 at 604, 605 & n.10.

Provided, however, that there shall be no deductions from the value of the Lessor's royalty by reason of any required processing, costs of dehydration, compression, transportation, or other matter to market such gas.³⁵¹

Based upon the inclusion in each lease of the foregoing proviso, the royalty owner objected to the lessee's deduction of certain transportation expenses from royalty payments made on production from such leases.³⁵² The lessee argued that the proper calculation of market value in royalty provisions of this type requires that transportation costs between the wellhead and the point of delivery must be taken into account, and that the enforcement of a provision disallowing the deduction of transportation costs when such a market value royalty payment standard is applicable would result in the payment of royalty on a basis other than that contracted for in the lease.³⁵³ Thus, the lessee argued that the foregoing proviso was intended only to prevent the lessee from deducting more than the "reasonable" costs of transporting the gas to market.³⁵⁴

The El Paso Court of Appeals rejected this argument, concluding that the lessee's argument rendered the quoted proviso meaningless. Attempting to harmonize and give meaning to all provisions of the affected leases, the court held the proviso to be enforceable, concluding that the parties had contemplated gas sales and, consequently, the calculation of royalty, away from the wellhead, and that the royalty

owners would not absorb any post-production costs.³⁵⁵

The Texas Supreme Court reversed the holding of the court of appeals and held that the provisions of the affected leases required the lessee to pay royalties based on the market value of the production at the well, taking into account appropriate deductions for transportation costs.³⁵⁶ According to the majority opinion of the court, written by Justice Baker and joined in by Chief Justice Phillips and Justices Cornyn, Enoch, and Spector, the most desirable method of determining market value is the use of comparable sales, but when information about comparable sales is not readily available, courts use a second method, which "involves subtracting reasonable post-production marketing costs from the market value at the point of sale."³⁵⁷ The court then stated that the well accepted trade meanings of the terms "royalty" and "market value at the well," both of which contemplate the deduction of transportation and other post-production costs in calculating royalty, rendered the quoted "no post-production cost" proviso mere "surplusage as a matter of law."³⁵⁸ The court stated further that the court of appeals' interpretation improperly converted the royalty clauses in issue from provisions requiring payment of royalty based on the "market value at the well" to provisions requiring the payment of royalty based on the "market value at the point of sale with no deductions for post-production costs."³⁵⁹ To avoid this result, the court characterized the quoted proviso as "merely stating existing

³⁵¹ *Heritage Res.*, 939 S.W.2d at 120-21.

³⁵² *Id.* at 120.

³⁵³ *Heritage Res.*, 895 S.W.2d 833, 836-37 (Tex. App. – El Paso 1995), *rev'd*, 939 S.W.2d 118 (Tex. 1996).

³⁵⁴ *Heritage Res.*, 895 S.W.2d at 836.

³⁵⁵ *Id.* at 837.

³⁵⁶ *Heritage Res.*, 939 S.W.2d at 123.

³⁵⁷ *Id.* at 122. In her concurring opinion, Justice Owen described the so-called net-back approach as one which "determines the prevailing market price at a given point and backs out the necessary reasonable costs between that point and the wellhead." *Id.* at 130.

³⁵⁸ *Heritage Res.*, 939 S.W.2d at 122-23.

³⁵⁹ *Id.* at 122.

law” to the effect that the lessee cannot pay “the lessor less than his fractional share of the value of the comparable sales price (market value).”³⁶⁰

8. So, Where Are We Now?

Where *Middleton* addressed and answered numerous legal issues with genuine clarity, *Heritage Resources* raises and leaves unanswered almost as many questions as it answers. For example:

a. What Is the Precedential Value of *Heritage Resources*? The question of the precedential value of *Heritage Resources* beyond the dispute in that case is legitimate. As pointed out by Justice Gonzalez, when Justices Cornyn, Spector, and Abbott joined in his second dissent filed in conjunction with the Texas Supreme Court’s March 1997 order overruling the lessor’s motion for rehearing, the court’s original “majority” opinion was no longer supported by a majority of the Justices.³⁶¹ It is noteworthy, in this regard, that *Yzaguirre*, decided by the Texas Supreme Court five years after *Heritage Resources*, does not contain a single citation or other reference to *Heritage Resources*.

Recently, the United States Court of Appeals for the Fifth Circuit directly addressed such a challenge to the precedential value of *Heritage Resources* in *Potts v. Chesapeake Exploration, L.L.C.*³⁶² In rejecting the lessor’s challenge, Judge Owen, who authored the concurring opinion in *Heritage Resources* before her appointment to the Fifth Circuit, stated, “Because rehearing was denied, the court’s

³⁶⁰ *Id.*

³⁶¹ *Id.* After *Heritage Resources* was released, one of the Justices recused himself from further proceedings in the case. As a result, when Justices Cornyn and Spector, who originally joined in the majority opinion, joined Justices Gonzalez and Abbott in dissent, the Justices split 4-4 in ruling on the motion for rehearing. See Watt, *supra* note 2, at 10.

³⁶² 760 F.3d 470 (5th Cir. 2014).

opinion in *Heritage* was not withdrawn. The Texas court’s decision in *Heritage* remains binding law . . .”³⁶³ Indeed, *Heritage Resources* has been cited as controlling precedent for one proposition or another in a number of subsequent Texas appellate decisions in addition to *Potts*.³⁶⁴

b. Why Did the Court Resort to the Net-Back Method to Determine Market Value? In *Heritage Resources*, neither party complained about the price the lessee received for the sale of its gas, and no comparable sale or other market value evidence was introduced at trial. The case is therefore not a traditional “market value v. actual sale price” controversy like *Vela* or *Middleton*. Rather, the plaintiff’s claim for underpayment of royalties was limited to its claim that transportation charges had been improperly deducted. The court was thus left with no conceptual framework for its market value analysis. The net-back method appears to have provided that framework in a manner that fit the needs of the case.³⁶⁵

c. Is a Showing That Comparable Sales Evidence Is Not Readily Available Required Before The Net-Back Method May Be Used? In market value royalty cases, the burden to prove market value at the well is on the plaintiff.³⁶⁶ In *Heritage Resources*,

³⁶³ *Id.* at 476.

³⁶⁴ *E.g.*, *Warren v. Chesapeake Exploration, L.L.C.*, 759 F.3d 413 (5th Cir. 2014); *Yturria v. Kerr-McGee Oil & Gas Offshore, LLC*, 291 Fed. Appx. 626 (5th Cir. 2008) (not designated for publication); *Ramming v. Natural Gas Pipeline Co.*, 390 F.3d 366 (5th Cir. 2004); *French v. Occidental Permian Ltd.*, 440 S.W.3d 1 (Tex. 2014); *Union Pacific Resources Group v. Hankins*, 111 S.W.3d 69 (Tex. 2003); and *Tana Oil and Gas Corp. v. Cernosek*, 188 S.W.3d 354 (Tex. App. – Austin 2005, *pet. denied*).

³⁶⁵ See *Heritage Res.*, 939 S.W.2d at 123; Watt, Ramos and Beckworth, *supra* note 2, at 15.

³⁶⁶ *Heritage Res.*, 939 S.W.2d at 122, citing *Texas Oil & Gas Corp. v. Hagen*, 683 S.W.2d 24, 29 (Tex. App. – Texarkana 1984), *aff’d in part and rev’d in part*, 1984 WL 47847 (Tex. 1987), *judgmt and op. of Tex. Supp. withdrawn, judgment of Tex. Civ. App. set*

the court noted that the lessor had offered no evidence of comparable sales and had conceded that the transportation costs deducted were reasonable, while the lessee had conceded that the price received from the sale of the gas was the market price at the point of sale. In the absence of evidence of comparable sales, the court stated that the net-back method would be used to determine the market value of the gas, but did not indicate whether a showing on this point was required.³⁶⁷ Although market value at the well cases decided based on comparable sales evidence have not totally disappeared from the landscape,³⁶⁸ most of the subsequent decisions involving determinations of market value at the well that have invoked the principles of *Heritage Resources* have contained similar statements regarding the unavailability or lack of comparable sales evidence.

For example, in *Ramming v. Natural Gas Pipeline Company of America*,³⁶⁹ a case involving lessor allegations of underpayment of royalties based on the lessee's alleged improper deduction of certain post-production costs, the Fifth Circuit stated that comparable sales provides the preferable method of determining market value at the well, and that the net-back method was to be used only when comparable sales are not

aside, and cause dismissed as moot, 760 S.W.2d 960 (Tex. 1988).

³⁶⁷ *Heritage Res.*, 939 S.W.2d at 123.

³⁶⁸ *E.g.*, *Yzaguirre v. KCS Res. Inc.*, 53 S.W.3d 368, 374-75 (Tex. 2001); *Occidental Permian Ltd. v. Helen Jones Foundation*, 333 S.W.3d 392, 406-407 (Tex. App. – Amarillo 2011, *pet. denied*) (in a case involving tertiary recovery operations utilizing the injection of CO₂ into the producing reservoir, the plaintiff/royalty owner's expert testimony concerning the market value of the high-CO₂ content gas produced from the tertiary recovery unit held to constitute "no evidence" of market value, because the expert failed to include high-CO₂ content gas in her comparability evaluation). See 1 SMITH & WEAVER, *supra* note at 155, § 4.6.C at 4-75.

³⁶⁹ 390 F.3d 366 (5th Cir. 2004).

available.³⁷⁰ In rejecting the lessor's claims and approving the lessee's determination of market value at the well (including the lessee's deduction of gathering and transportation charges), the court noted that "the plaintiff offer[ed] no evidence of comparable sales or evidence that the gathering charge deducted was not reasonable."³⁷¹ Similarly, in *Potts v. Chesapeake Exploration, L.L.C.*,³⁷² the Fifth Circuit affirmed a district court holding approving Chesapeake's calculation of market value at the well using net-back methodology after neither Chesapeake nor the plaintiff lessor were able to make any evidentiary showing of comparable sales at the wellhead.³⁷³ On the other hand, in *French v. Occidental Permian Ltd.*,³⁷⁴ a case involving, in part, the determination of market value at the well of gas production from a CO₂ flood unit based on a *Middleton* Lease Royalty Clause, the Texas Supreme Court adopted the net-back methodology with no reference whatsoever to comparable sales, except for the statement that "the only market value evidence in this case is of the NGLs and residue gas at the tailgate of the [processing] plant, after processing is complete."³⁷⁵

Based on the cases reviewed, the courts do not appear consistently to be requiring an evidentiary showing of no comparable sales as a condition precedent to applying the net-back method to determine market value at the well. Nonetheless, it seems like good practice for litigants desiring to use the net-back method, rather than comparable sales, to determine market value at the well to attempt to demonstrate why comparable

³⁷⁰ *Id.* at 372.

³⁷¹ *Id.* at 374.

³⁷² 760 F.3d 470 (5th Cir. 2014).

³⁷³ *Id.* at 471, *aff'd* 2013 WL 874711 at 7 (N.D. Tex. 2013) (*mem. op.*).

³⁷⁴ 440 S.W.3d 1 (Tex. 2014).

³⁷⁵ *Id.* at 8.

sales information is unavailable.³⁷⁶ Conversely, it seems incumbent on litigants attempting to avoid the application of the net-back method to make a convincing showing of market value at the well based on comparable sales at the well.

d. Did the Court Really Intend To Establish “Market Value at the Point Of Sale” as the Starting Point for the Net-Back Method? As discussed above, the majority opinion in *Heritage Resources* stated that the net-back method of determining market value at the well “involves subtracting reasonable post-production marketing costs from the *market value at the point of sale*” (emphasis added).³⁷⁷ Several commentators have suggested that the Texas Supreme Court erred in not using the “actual price” received at the point of sale as the starting point for the net-back calculation,³⁷⁸ as courts in some other jurisdictions have done,³⁷⁹ arguing that the reference to “market value” produces “an illogical and circular result.”³⁸⁰

³⁷⁶ See Watt, Ramos and Beckworth, *supra* note 2, at 15-16.

³⁷⁷ *Heritage Res.*, 939 S.W.2d at 122, citing *Texas Oil & Gas Corp. v. Hagen*, 683 S.W.2d 24, 29 (Tex. App. – Texarkana 1984), *aff’d in part and rev’d in part*, 1987 WL 47847 (Tex. 1987), *judgmt and op. of Tex. Sup. withdrawn, judgmt of Tex. Civ. App. set aside, and cause dism’d as moot*, 760 S.W.2d 960 (Tex. 1988). Justice Owen’s concurring opinion describes “the so-called net-back approach” to determining market value at the well as establishing “the prevailing market price at a given point and back[ing] out the necessary, reasonable costs between that point and the wellhead.” *Heritage Res.*, 939 S.W.2d at 130 (Owen, J., concurring).

³⁷⁸ See Watt, *supra* note 2, at 26-27; Watt, Ramos and Beckworth, *supra* note 2, at 15.

³⁷⁹ *E.g.*, *Ashland Oil, Inc. v. Phillips Petroleum Co.*, 554 F.2d 381, 387 (10th Cir. 1977), *on remand*, 463 F. Supp. 619 (N.D. Okla. 1978), *aff’d in part, rev’d in part*, 607 F.2d 355 (10th Cir. 1979), *cert. denied*, 446 U.S. 936 (1980) (“Under this method, a point was selected where there can be determined an established price and the costs of processing or transportation were deducted to move back to the place where the value must be established.”).

³⁸⁰ See Watt, *supra* note 2, at 27.

While several aspects of *Heritage Resources* have an “Alice Through the Looking Glass”³⁸¹ character to them, I am not sure that this issue is one of them. Conceptually, it is certainly possible to calculate market value at any of a number of points – at the wellhead, at the tailgate of a processing plant, or at other points of sale or resale. As such, the use of a market value “at the point of sale” as the starting point for a net-back calculation of market value “at the well” does not, in and of itself, appear to produce a circular result.

The “market value at the point of sale” formulation is consistent with the description of the net-back method in *Piney Woods*³⁸² and has been incorporated faithfully into several post-*Heritage Resources* decisions in Texas.³⁸³ In particular, *Potts* serves as a roadmap for how such an analysis would work. In *Potts*, COI, the lessee’s operating company affiliate, as agent for the lessee, sold the gas produced from the relevant lease to CEMI, the lessee’s marketing affiliate, at the wellhead. CEMI then caused the gas to be gathered, transported, and delivered for resale to unaffiliated gas purchasers at one or more pipeline hubs located substantial distances from the leased premises. The applicable lease royalty clause required the payment of royalty on gas production based on “the market value at the point of sale of the gas sold or used . . .”³⁸⁴ The lease also

³⁸¹ Lewis Carroll, THROUGH THE LOOKING GLASS, AND WHAT ALICE FOUND THERE (McMillan 1871).

³⁸² *Piney Woods Country Life School v. Shell Oil Co.*, 726 F.2d 225, 240 (5th Cir. 1984), *cert. denied*, 471 U.S. 1005 (1985) (“The next best method is to examine sales of sweet gas and sulfur, to determine the market value of the products resulting from processing . . . Processing costs may then be deducted as an indirect means of determining what a buyer would have paid for the sour gas at the wellhead.”)

³⁸³ *E.g.*, *Potts v. Chesapeake Exploration, L.L.C.*, 760 F.3d 470 (5th Cir. 2014); *Ramming v. Natural Gas Pipeline Co.*, 390 F.3d 366 (5th Cir. 2004); *French v. Occidental Permian Ltd.*, 440 S.W.3d 1 (Tex. 2014).

³⁸⁴ *Potts*, 760 F.3d at 471.

provided that the royalty would be calculated “free of all costs and expenses related to the exploration, production and marketing” of such gas production, including compression, dehydration, treatment, and transportation costs.³⁸⁵

Rather than simply paying royalty based on the sales proceeds received by COI from CEMI at the wellhead, the lessee paid royalty based on a net-back calculation of market value at the well equal to the volume weighted average sales price received by CEMI from its downstream resales of gas to unaffiliated gas producers less the post-production costs incurred between the wellhead and the points of delivery to the gas purchasers.³⁸⁶ In the absence of comparable sales evidence to the contrary, the Fifth Circuit upheld the lessee’s determination of market value at the well.³⁸⁷

Indeed, the “market value at the point of sale” formulation is consistent with the Texas courts’ recognition that there is a difference between the market value and the amount realized royalty payment standards.³⁸⁸ The use of the “actual sales

price” as the starting point for a net-back market value determination would erode the distinction between the two royalty payment standards. The court’s “market value at the point of sale” formulation ostensibly prevents that result from occurring.

e. Does the Net-Back Method Produce a Different Market Value than Comparable Sales Evidence? In many circumstances, almost certainly. It should be kept in mind that in virtually all of the cases reviewed, the net-back method is the “second choice” for determining market value at the well in the absence of suitable comparable sales evidence and is characterized as an “indirect means” of determining market value at the well.³⁸⁹ Inherent in that characterization is the acknowledgment – perhaps even the expectation – that the net-back method is likely only to approximate the market value at the well determined based on comparable sales evidence.

f. Does the Use of the Net-Back Method Affect the Implied Marketing Covenant Analysis with Respect to Market Value? Some commentators have suggested that the use of the net-back method may reopen the issue of the applicability of the implied covenant to market when royalty is based on the market value at the well. The argument assumes that the “true” starting point for the net-back calculation is the actual price from the sale. As such, the higher the actual sale price, the higher the market value at the well following the net-back. Therefore, so the argument goes, the implied covenant to market should operate, as it does in the case of an amount realized royalty clause, to require the lessee to obtain the best price reasonably possible for the gas.³⁹⁰

³⁸⁵ *Id.* at 471-72.

³⁸⁶ *Id.* at 472. Unlike the *Middleton* Lease Royalty Clause, the royalty clause in *Potts* did not provide for an “amount realized” royalty standard for sales at the well. Apparently not satisfied that the wellhead sale price paid by CEMI to the lessee accurately reflected the market value of the gas at the well, the lessee calculated the market value at the well using the net-back methodology described above. See text accompanying notes 674 through 683, *infra*.

³⁸⁷ *Id.* at 475.

³⁸⁸ As stated by the Texas Supreme Court, “If the parties intended royalties to be calculated on the amount realized standard, they could and should have used *only* a ‘proceeds-type’ clause. . . . The parties did not use ‘market value’ and ‘amount realized’ interchangeably and we reject Exxon’s assertion that the parties intended ‘market value’ to have essentially the same meaning as ‘amount realized.’” *Exxon Corp. v. Middleton*, 613 S.W.2d 240, 245 (Tex. 1981). *Accord, Yzaguirre v. KCS Res., Inc.*, 53 S.W.3d 368, 373 (Tex. 2001); *Amoco Prod. Co. v. First Baptist Church*, 611 S.W.2d 610 (Tex. 1980); *Texas Oil & Gas Corp. v. Vela*, 429 S.W.2d 866, 872 (Tex. 1968).

³⁸⁹ See, e.g., *Piney Woods*, 726 F.2d at 240.

³⁹⁰ See Watt, *supra*, note 2, at 30-31. In support of this argument, the commentator cites language from the Texas Supreme Court’s opinion in *Phillips Petroleum Co. v. Yarbrough*, 405 S.W.3d 70, 78 (Tex. 2013), to the effect that, “A duty to market is implied

While this argument obviously provides some “red meat” for royalty owners and their lawyers with respect to the implied marketing covenant issue, it should be noted that, based on the cases we have reviewed, the Texas courts have never endorsed the actual sale price received at the point of sale as the starting point for a net-back calculation of market value at the well. On the contrary, the Texas courts have consistently used the “market value at the point of sale” as the starting point for the net-back analysis.³⁹¹ Consequently, it seems unlikely that the use of the net-back method will have any impact on the issue of the applicability of the implied covenant to market to the determination of market value at the well.

F. Costs Chargeable to Royalty.

1. General Concepts.

Both the *Middleton* Lease Royalty Clause and the 4/76 Royalty Clause are silent concerning the extent, if any, that the lessor’s royalty is burdened by taxes, costs, and expenses incurred by the lessee. As a general proposition, under Texas law, all royalty interests, including the lessor’s royalty interest under an oil and gas lease, are non-possessory interests in real property that are free of all costs of exploration, drilling, production, and operations conducted on the leased premises.³⁹² In the case of a true sale of

in leases that base royalty calculations on the price received by the lessee for the gas.”

³⁹¹ See notes 173 through 184 and accompanying text, *supra*.

³⁹² *E.g.*, *Heritage Res. Inc. v. NationsBank*, 939 S.W.2d 118, 121-122 (Tex. 1996); *Blackmon v. XTO Energy, Inc.*, 276 S.W.3d 600, 604 (Tex. App. – Waco 2008, *no pet.*); *Cartwright v. Cologne Production Co.*, 182 S.W.3d 438, 444 (Tex. App. – Corpus Christi-Edinburg 2006, *pet. denied*) (“Production costs are the expenses incurred in exploring for mineral substances and in bringing them to the surface.”); *Parker v. TXO Production Co.*, 716 S.W.2d 644, 648 (Tex. Civ. App. – Corpus Christi 1986, *no writ*); *Alamo Nat’l Bank of San Antonio v. Hurd*, 485 S.W. 2d 335, 338 (Tex. Civ. App. – San Antonio 1972, *writ ref’d*

gas at the wellhead, the courts have held that no post-production costs and expenses, other than the royalty owner’s proportionate share of ad valorem, gross production, and severance taxes, may be charged against the royalty interest because the price paid for the gas at the wellhead is presumed to be based on its value before transportation, processing, and other post-production activities.³⁹³

When leases provide for the payment of royalty based upon either the market value or the amount realized “at the well,” and the actual sale of production occurs at a location other than the wellhead, then absent a contrary provision in the applicable lease, Texas courts have permitted producers to deduct reasonable post-production costs actually incurred by the producer for purposes of calculating royalty.³⁹⁴ This result is based on two

n.r.e.). See 1 SMITH & WEAVER, *supra* note 155, §2.4 at 51.

³⁹³ *E.g.*, *Potts v. Chesapeake Exploration, L.L.C.*, 760 F.3d 470, 473-474 (5th Cir. 2014) (“If . . . the lessee sells the gas at the well, there generally will be no post-production costs incurred by the lessee.”); *Piney Woods Country Life School v. Shell Oil Co.*, 726 F.2d 225, 240 (5th Cir. 1984), *cert. denied*, 471 U.S. 1005 (1985) (“... [P]rocessing costs may not be deducted from royalties for gas ‘sold at the well’, because the price of such gas is based on its value before processing.”); *Pan American Petroleum Corp. v. Southland Royalty Co.*, 396 S.W.2d 519, 524 (Tex. Civ. App. – El Paso 1965, *writ dismissed*) (“... [T]here are no properly deductible items of expense involved in the sale of gas . . . as it is set forth without dispute that the gas flows from the wells by its own power, some thirty to sixty feet, to a separator and/or meter and pipeline installed by the purchaser.”)

³⁹⁴ *E.g.*, *Ramming v. Natural Gas Pipeline Co. of America*, 390 F.3d 366, 372 (5th Cir. 2004); *Martin v. Glass*, 571 F. Supp. 1406, 1411-1412 (N.D. Tex. 1983), *aff’d without opinion*, 736 F.2d 1524 (5th Cir. 1984); *Chesapeake Exploration, L.L.C. v. Hyder*, 2015 WL 3653446 at 3 (Tex. 2015); *Heritage Res. Inc. v. NationsBank*, 939 S.W.2d 118, 122 (Tex. 1996); *Cartwright v. Cologne Production Co.*, 182 S.W.3d 438, 444-445 (Tex. App. – Corpus Christi-Edinburg 2006, *pet. denied*); *Parker v. TXO Production Co.*, 716 S.W.2d 644, 648 (Tex. Civ. App. – Corpus Christi 1986, *no writ*); *LeCuno Oil Co. v. Smith*, 306 S.W.2d 190, 193 (Tex. Civ. App. – Texarkana 1957, *writ ref’d n.r.e.*), *cert. denied*, 356

related premises. The first premise concerns the significance of the phrase “at the well” and was articulated by the Fifth Circuit in *Piney Woods* as follows:

“At the well” means that gas has not been increased in value by processing or transportation. It has this meaning in conjunction with “value” or “amount realized” as well as with “sold”. The lessors under these leases are therefore entitled to royalty based on the value or price of unprocessed, untransported gas. [citations omitted] On royalties “at the well”, therefore, the lessors may be charged with . . . all expenses, subsequent to production, relating to the processing, transportation, and marketing of gas and sulphur.³⁹⁵

The second and related premise, which arises out of the implied covenant to market, is that the lessee has satisfied his expressed and implied obligations under the oil and gas lease to obtain a marketable product by obtaining gas production in paying quantities, such that the lessee should not be required to bear alone the costs of further enhancement of the production obtained. This approach is contrary to the approach taken by the courts in several mid-continent states, which have concluded that the obligation to render production marketable imposed by their formulation of the implied covenant to market (known as the “marketable condition” rule) includes post-production compression, dehydration, gathering, and, in some cases, transportation activities, so

U.S. 974 (1958). See 1 SMITH & WEAVER, *supra* note 155, §4.6.C at 195.

³⁹⁵ *Piney Woods Country Life School v. Shell Oil Co.*, 726 F.2d 225, 240 (5th Cir. 1984), *cert. denied*, 471 U.S. 1005.

that the costs associated therewith are not properly deductible from royalty.³⁹⁶ In these cases, language providing for the calculation of royalty “at the well” has not been a factor in the courts’ decisions.

2. Heritage Resources.

In *Heritage Resources, Inc. v. NationsBank, Co., Trustee*,³⁹⁷ the Texas Supreme Court expressly rejected the approach of the Oklahoma, Kansas, and Colorado courts to these issues and affirmed the deductibility, under Texas law, of post-production costs in calculating royalty based upon “market value at the well.” The specific facts and holding in *Heritage Resources* were discussed in Section III.E.7.b of this paper.³⁹⁸ In the context of this discussion of post-production costs, Justice Owens’ concurring opinion, joined in by Justice Hecht, is of particular interest.

³⁹⁶ In Oklahoma, Kansas, and Colorado, the courts have held that the obligation to render production marketable imposed on the lessee by these states’ formulation of the implied covenant to market precludes the deduction of post-production costs of compression, dehydration, gathering, and, in some cases, transportation in calculating royalty. *E.g.*, *Bailey v. Shell Western E&P, Inc.*, 609 F.3d 710, 723-724 (5th Cir. 2010) (applying Colorado law), *cert. denied*, ___ U.S. ___, 131 S. Ct. 428 (2010); *Rogers v. Westerman Farm Co.*, 29 P.3d 887, 903-06 (Colo. 2001); *Garman v. Conoco Inc.*, 886 P.2d 652 (Colo. 1994); *Wood v. TXO Prod. Corp.*, 854 P.2d 880 (Okla. 1992); *Gilmore v. Superior Oil Co.*, 192 Kan. 388, 388 P.2d 602 (Kan. 1964); *Schupbach v. Continental Oil Co.*, 193 Kan. 401, 394 P.2d 1 (Kan. 1964). Oklahoma law, at least, obligates the lessor to bear its proportionate share of transportation costs when the point of sale is off the leased premises. *Wood v. TXO Prod. Corp.*, 854 P.2d 880 (Okla. 1992); *Johnson v. Jernigan*, 475 P.2d 396 (Okla. 1970). For comprehensive treatments of the law relating to post-production costs in most of the producing states, see Theriot and Downer, *supra* note 2; Lipe and Phillips, *supra* note 2; Rodriguez and Phillips, *supra* note 2, at 13; Rodriguez and Mayer, *supra* note 2, at Ch. 7; Edward B. Poitevent, II, “*Post-Production Deductions From Royalty*,” 29 OIL, GAS & ENERGY RES. L. SECTION REPORT, St. Bar of Tex., No. 1, at 38 (2004).

³⁹⁷ 939 S.W.2d 118 (Tex. 1996).

³⁹⁸ See text accompanying notes 349 through 360, *supra*.

First, after undertaking an exhaustive review of the authorities in Texas and other states concerning the deductibility of post-production costs in calculating royalty,³⁹⁹ Justice Owen found persuasive the Fifth Circuit's analysis in *Piney Woods* that the phrase "at the well" is intended to distinguish between gas sold in the form in which it emerges from the wellhead and gas that thereafter has value added by transportation or processing.⁴⁰⁰ Justice Owen further expressly rejected the "marketable condition" rule adopted by the Oklahoma, Kansas, and Colorado courts.⁴⁰¹

Having concluded that post-production costs are to be shared by the royalty owners under a "market value at the well" royalty provision, Justice Owen next addressed the effect of the proviso in the oil and gas lease in controversy purporting to prohibit the deduction of such costs as follows:

The concept of deductions of marketing costs from the value of gas is meaningless when gas is valued at the well. Value at the well is already net of reasonable marketing costs. The value of gas "at the well" represents its value in the market place at any given point of sale, less the reasonable costs to get the gas to that point of sale, including compression, transportation, and processing costs. . . . As 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. . . . It could not be said that under that circumstance that the clause is ambiguous. It could only be said that the proviso is surplusage.⁴⁰²

In a vigorous dissent, Justice Gonzalez, joined by Justice Abbott, strongly objected to the majority's decision "to ignore the unequivocal intent of sophisticated parties who negotiated contractual terms at arm's length," and concluded that both the trial court and the court of appeals had correctly held that the quoted proviso prevented the lessee from deducting transportation costs in the calculation of the market value of the gas for royalty purposes.⁴⁰³ Justice Gonzalez continued his criticism of the majority and concurring opinions in a second dissent filed in conjunction with the supreme court's order overruling the lessor's motion for rehearing in March 1997.⁴⁰⁴ In his second dissent, Justice Gonzalez was joined by Justices Cornyn and Spector, who had originally joined in the majority opinion, as well as Justice Abbott. Justice Gonzalez argued that, *inter alia*, because the court was without a majority in the case, the judgment should control only the case at bar and otherwise have limited precedential value.⁴⁰⁵

3. Must Not the Parties in *Heritage Resources* Have Intended Something by the Inclusion of the "No Post-Production Costs" Provisions in their Leases?

The conclusion of the El Paso Court of Appeals in *Heritage Resources* that "no

³⁹⁹ *Heritage Res.*, 939 S.W.2d at 127-129.

⁴⁰⁰ *Id.* at 127. See text accompanying note 395, *supra*.

⁴⁰¹ *Heritage Res.*, 939 S.W.2d at 129-30.

⁴⁰² *Id.* at 130-131. Contrast with *Rogers v. Westerman Farm Co.*, 29 P.3d 887, 897 (Colo. 2001), in which the Colorado Supreme Court stated that the phrase "at the well" is silent as to the allocation of post-production costs.

⁴⁰³ *Heritage Res.*, 939 S.W.2d at 131-32.

⁴⁰⁴ 40 Tex. Sup. Ct. J. 445 (Tex. 1997).

⁴⁰⁵ *Id.* at 447.

post-production costs” provision in the lease in controversy moved the point of royalty calculation away from the wellhead downstream to the point of sale⁴⁰⁶ seems to be a reasonable reconciliation of that provision with the market value at the well royalty clause. Even if one does not accept that reconciliation, however, the inclusion in a conventional market value royalty clause of a provision expressly prohibiting the deduction of post-production costs appears to create a patent ambiguity that should have permitted the application of the customary rules of contract interpretation relating to ambiguous agreements, including the introduction, if appropriate, of extrinsic evidence of the intent of the parties. Neither the El Paso Court of Appeals nor the Texas Supreme Court, however, found the relevant royalty clauses ambiguous in any way, even though the courts reached completely different conclusions concerning their meanings.⁴⁰⁷

It is these courts’ refusal to identify such an ambiguity that is the most “Alice Through the Looking Glass”⁴⁰⁸ aspect of *Heritage Resources* for this author, particularly in light of the court’s decision in *Judice v. Mewbourne*,⁴⁰⁹ decided on the same day as *Heritage Resources*. In *Judice*, the Texas Supreme Court found such a patent ambiguity in the phrase “gross proceeds realized at the well” as used in a division order. Stating that the term “gross proceeds” means that royalty is to be calculated by reference to the gross price received by the lessee, while the phrase “at the well” contemplates the deduction of post-production costs in the calculation of royalty, the court concluded that, based on the extrinsic evidence presented at trial, the

parties had intended royalty to be calculated based upon the price received by the lessee without deduction for compression charges.⁴¹⁰

At the end of the day, however, *Heritage Resources* and the subsequent cases applying its principles appear clearly to have established as the law in Texas that:

- the phrase “at the well”, when used in the calculation of gas royalty – whether pursuant to a “market value”,⁴¹¹ “amount realized”,⁴¹² “net proceeds”,⁴¹³ or other royalty clause – refers to gas in its natural state as produced and that has not been increased in value by gathering, processing, or transportation;
- when the net-back method is used to determine the amount owed as royalty on gas production “at the well”, costs of gathering, processing, transportation, and other “reasonable post-production costs” must be applied against the market value of, or the amount realized or gross proceeds from the sale of, the gas at its point of sale in order to determine the market value of, or the

⁴¹⁰ *Id.* at 136-37.

⁴¹¹ *E.g.*, *Potts v. Chesapeake Exploration, L.L.C.*, 760 F.3d 470 (5th Cir. 2014); *Ramming v. Natural Gas Pipeline Co.*, 390 F.3d 366 (5th Cir. 2004); *French v. Occidental Permian Ltd.*, 440 S.W.3d 1 (Tex. 2014).

⁴¹² *Warren v. Chesapeake Exploration, L.L.C.*, 759 F.3d 413 (5th Cir. 2014); *Yturria v. Kerr-McGee Oil Gas Onshore, LLC*, 291 Fed. Appx. 626 (5th Cir. 2008) (not designated for publication); *Chesapeake Exploration, L.L.C. v. Hyder*, 427 S.W.3d 472 (Tex. App. – San Antonio 1996, *pet. granted*); *Occidental Permian Ltd. v. Helen Jones Foundation*, 333 S.W.3d 392 (Tex. App. – Amarillo 2011, *pet. denied*); *Tana Oil and Gas Corp. v. Cernosek*, 188 S.W.3d 354 (Tex. App. – Austin 2005, *pet. denied*).

⁴¹³ *E.g.*, *French v. Occidental Permian Ltd.*, 440 S.W.3d 1 (Tex. 2014); *Cartwright v. Cologne Production Co.*, 182 S.W.3d 438 (Tex. App. – Corpus Christi 2006 *pet. denied*); *Niemeyer v. Tana Oil and Gas Corp.*, 39 S.W.3d 380 (Tex. App. – Austin 2001, *pet. denied*).

⁴⁰⁶ *Heritage Res.*, 895 S.W.2d 833, 836-37 (Tex. App. – El Paso 1995), *rev’d*, 939 S.W.2d 118 (Tex. 1996).

⁴⁰⁷ *See Heritage Res.*, 939 S.W.2d at 132 (Gonzalez, J., dissenting).

⁴⁰⁸ *See* note 381, *supra*.

⁴⁰⁹ 939 S.W.2d 133 (Tex. 1996).

amount realized or net proceeds from the sale of, such gas “at the well”; and

- attempts to prevent contractually post-production costs from being subtracted in the net-back calculation of royalty valued “at the well” almost certainly will be treated as “surplusage as a matter of law” and not enforced by the courts.

The key, then, for lessors attempting to insulate themselves from exposure to post-production costs appears to be to stop providing for the calculation of royalty “at the well.” As Justice Owen stated in her concurring opinion in *Heritage Resources*:

If [the parties] had intended that the royalty owners would receive royalty based on market value at the point of *delivery* or *sale*, they could have said so. If they had intended that *in addition* to the payment of market value at the well, the lessee would pay all post-production costs, they could have said so. They did not.⁴¹⁴

To date, royalty owner attempts to insulate themselves from post-production costs by using royalty clauses different from the *Middleton* Lease Royalty Clause model have met with limited success, mostly because of their inability to eliminate completely the “at the well” concept from their leases. For example, recall that in *Potts*,⁴¹⁵ the applicable lease required the payment of royalty on gas production based on “the market value at the point of sale of the gas sold or used . . .”, subject to a no-post-production costs provision.⁴¹⁶ Because

⁴¹⁴ *Heritage Res.*, 939 S.W.2d at 131 (Owen, J., concurring).

⁴¹⁵ *Potts v. Chesapeake Exploration, L.L.C.*, 760 F.3d 470 (5th Cir. 2014).

⁴¹⁶ *Id.* at 471-72.

the gas was sold at the wellhead, however, the Fifth Circuit determined that the market value royalty must be determined “at the well”.⁴¹⁷ Then, applying the net-back method as described in *Heritage Resources*, the court upheld the lessee’s calculation of market value at the well as the volume weighted average sales price received by the lessee’s marketing affiliate upon its resale of the gas to unaffiliated gas purchasers less the post-production costs incurred between the wellhead and the points of delivery to the gas purchasers, notwithstanding the presence of the no-post-production costs provision.⁴¹⁸

Similarly, in *Warren v. Chesapeake Exploration, L.L.C.*,⁴¹⁹ the lease in controversy required the payment of royalty on gas production based on “the amount realized by Lessee, computed at the mouth of the well . . .”, subject to a no-post-production costs provision similar to that in *Potts*.⁴²⁰ Because royalty was required to be determined “at the mouth of the well”, the Fifth Circuit, once again applying *Heritage Resources*, held that royalty should be calculated, pursuant to the net-back method, based on the amount realized by the lessee upon the sale of the gas production less the post-production costs incurred between the wellhead and the points of sale, again notwithstanding the presence of the no-post-production costs provision.⁴²¹

Recently, however, the royalty owners won in two cases involving non-standard royalty clauses. First, in *Yturria v. Kerr-McGee Oil Gas Onshore, LLC*,⁴²² the oil and gas leases in controversy provided, in pertinent part, for

⁴¹⁷ *Id.* at 473-74.

⁴¹⁸ *Id.* at 475.

⁴¹⁹ 759 F.3d 413 (5th Cir. 2014).

⁴²⁰ *Id.* at 416.

⁴²¹ *Id.* at 418-19.

⁴²² 291 Fed. Appx. 626 (5th Cir. 2008) (not designated for publication).

a royalty of “one-fourth (1/4) of seventy-five percent (75%) of all plant products, or revenue derived therefrom, attributable to gas produced by [the lessee] from the leased premises.”⁴²³ The leases also contained conventional no-post-production costs provisions similar to those in *Potts and Warren*.⁴²⁴ The lessee processed the gas for the removal of NGLs under a variation of a percentage of proceeds, or “POP”, contract, pursuant to which a third party gas processor took title to the lessee’s gas, processed and fractionated the gas to remove the NGLs, and paid the lessee a price equal to 80% of the processor’s “Net Proceeds”, which consisted of the total value of the fractionated NGLs based on an average of index prices paid for NGLs at various plants, less the costs of marketing, transportation, and fractionation.⁴²⁵

The lessors complained that the lessee had improperly deducted post-production costs in its calculation of royalty, arguing that the phrase “all plant products, or the revenue derived therefrom” in the lease royalty clauses required that royalty be paid based on the index price per gallon of all NGLs received by the third party processor before the deduction of post-production costs. The lessors also contended that their interpretation of the royalty clauses was bolstered by the presence of the no-post-production costs provision. The lessee argued, on the other hand, that it had properly accounted to the lessors for royalty because it had paid them the royalty fraction of the proceeds it received from the third party processor under its POP contract.⁴²⁶ The United States Court of Appeals for the Fifth Circuit affirmed the judgment of the district court in favor of the lessors.⁴²⁷

⁴²³ *Id.* at 629-630.

⁴²⁴ *Id.* at 628.

⁴²⁵ *Id.*

⁴²⁶ *Id.* at 630.

⁴²⁷ *Id.* at 635.

Citing *Heritage Resources*, the Fifth Circuit focused on determining the value of the lessors’ royalty before assessing the impact of the no-post-production costs provisions.⁴²⁸ Based on its analysis of the language of the royalty clause, including extrinsic evidence introduced at trial regarding the circumstances under which the parties agreed to such royalty clause,⁴²⁹ the court rejected the lessee’s interpretation and held that the phrase “all plant products, or the revenue derived therefrom” (emphasis added), required royalty to be calculated based on the index prices per gallon payable under the lessee’s POP contract with the third party processor for all NGLs extracted from the lessee’s gas before any deductions for post-production costs.⁴³⁰ In so holding, the court, interestingly, made no further mention of the no-post-production costs provisions.

The more significant of the two cases is the Texas Supreme Court’s 2015 decision in *Chesapeake Energy, L.L.C. v. Hyder*.⁴³¹ In *Hyder*, the applicable lease contained a non-standard royalty clause that provided, in pertinent part:

(b) for natural gas, including casinghead gas and other gaseous substances produced from the Leased Premises and sold or used on or off the Leased Premises, twenty-five percent (25%) of the price actually received by [Lessee] for such gas *The royalty reserved herein by*

⁴²⁸ *Id.* at 631-632.

⁴²⁹ *Id.* at 633-634. According to the court, the current language of the royalty clauses in the *Yturria* leases was the result of a lease amendment entered into by the parties as part of the settlement of prior litigation in which the lessors had objected to various aspects of the lessee’s gas processing arrangement with one of its affiliates. *Id.*

⁴³⁰ *Id.* at 634-635.

⁴³¹ 2015 WL 3653446 (Tex. 2015).

[Lessors] 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 well-head and [Lessee's] point of delivery or sale of such share to a third party. [emphasis added]⁴³²

The lease also provided that the holding in *Heritage Resources* “shall have no application to the terms and provisions of this Lease.”⁴³³

As was the case in *Potts*,⁴³⁴ the gas produced from the *Hyder* lease was sold by the producer to its marketing affiliate at the wellhead. The marketing affiliate then gathered the gas through the facilities of its midstream affiliate to multiple “points of delivery” – i.e., points of interconnection between the marketing affiliate’s gathering facilities and multiple unaffiliated transporting pipelines. From the points of the delivery, the marketing affiliate caused the gas to be transported downstream to multiple “points of sale”, where the gas was resold to unaffiliated gas purchasers.⁴³⁵ The producer’s marketing affiliate paid the producer a price for the wellhead gas sales (the “net-back wellhead price”) equal to the weighted average of the resale prices received from the unaffiliated gas purchasers at the points of sale, less gathering and transportation costs incurred

between the points of delivery and the points of sale and a 3% marketing fee. The producer then accounted to the royalty owners based on the net-back wellhead price.⁴³⁶ The lessors alleged that the lessee underpaid royalties by improperly deducting post-production costs incurred between the points of delivery and the points of sale.⁴³⁷

After discussing the holding in *Heritage Resources* (including an acknowledgement that the Texas Supreme Court did not directly address “the apparent conflict” between the definition of “market value at the well” and the no-post-production costs provision in the *Heritage Resources* lease),⁴³⁸ the San Antonio Court of Appeals rejected the lessee’s interpretation of the *Hyder* lease, holding that an interpretation of the lease that permitted the deduction of post-production costs between the points of delivery and the points of sale was “contrary to the plain reading of the royalty clause.”⁴³⁹ In so holding, the court upheld the “free and clear of post-production costs” language in the *Hyder* lease and, giving effect to the anti-*Heritage Resources* provision, concluded that the holding in *Heritage Resources* did not apply based on the terms of the *Hyder* lease.⁴⁴⁰

On June 12, 2015, the Texas Supreme Court affirmed the judgment of the court of appeals and held that the royalty on gas produced from the *Hyder* lease “does not bear postproduction costs.”⁴⁴¹ Unlike the court of appeals, which relied primarily on the “free and clear of post-production costs” language in the royalty clause and, to a lesser extent, the anti-*Heritage Resources* clause as support for its holding, Justice

⁴³² 427 S.W.3d 472, 476 (Tex. App. – San Antonio 2014), *aff’d*, 2015 WL 3653446 (Tex. 2015).

⁴³³ *Hyder*, 427 S.W.3d at 477.

⁴³⁴ See notes 383-385 and accompanying text, *supra*.

⁴³⁵ *Hyder*, 427 S.W.3d. at 475.

⁴³⁶ *Id.*; 2015 WL 3653446 at 3 and n. 7.

⁴³⁷ *Hyder*, 427 S.W.3d at 476.

⁴³⁸ *Id.* at 477.

⁴³⁹ *Id.*

⁴⁴⁰ *Id.* at 477-78.

⁴⁴¹ *Chesapeake Exploration, L.L.C. v. Hyder*, 2015 WL 3653446 (Tex. 2015).

Hecht, writing for the majority,⁴⁴² looked solely to the “price actually received by the [Lessee]” language of the royalty clause as being dispositive. According to the court, “often referred to as a ‘proceeds lease’, the price-received basis for payment is sufficient in itself to excuse the lessors from bearing postproduction costs.”⁴⁴³

In so holding, the supreme court stated that the “free and clear of post-production costs” language in the royalty clause “has no effect on the meaning of the provision”, adding that this language “might be regarded as emphasizing the cost-free nature of the gas royalty, or as surplusage.”⁴⁴⁴ The court also gave no effect to the anti-*Heritage Resources* provision, stating:

A disclaimer of [the holding in *Heritage Resources*], like the one in this case, cannot free a royalty of postproduction costs when the text of the lease does not do so. Here, the lease text clearly frees the gas royalty of postproduction costs. . . .⁴⁴⁵

Hyder thus provides a roadmap for lessors seeking to escape from post-production cost exposure, although it is a different roadmap than the one that most lessor’s counsel have been following since *Heritage Resources* was decided.

4. The Meaning of “Cost-Free”.

Hyder also addressed a second set of issues related to the use of the phrase “cost free” in describing an overriding royalty interest. In addition to the conventional lessor’s royalty discussed above in Section

III.F.3 of this paper,⁴⁴⁶ the *Hyder* lease also provided that:

[Lessee] shall, within sixty (60) days from the date of the first production from each off-lease well, convey to [Lessor] a perpetual, cost free (except only its portion of production taxes) overriding royalty of five percent (5%) of gross production obtained from each such well payable to [Lessor]. . . . [emphasis added]⁴⁴⁷

The lessor argued that the phrase “cost free” was intended to mean that the overriding royalty was to be calculated without deduction for both production and post-production costs, while the lessee argued that the language merely reinforced Texas law that overriding royalties are calculated free of costs of production.⁴⁴⁸

The San Antonio Court of Appeals affirmed the trial court judgment in favor of the lessors and held that the lessor was entitled to an overriding royalty free of both production and post-production costs.⁴⁴⁹ In particular, the court found that the language carving out production taxes, which are normally treated as post-production costs, as an exception to the “cost free” concept indicated an intent that “cost free” referred to both production and post-production costs, and that to hold otherwise would require the court to re-write the *Hyder* lease.⁴⁵⁰

⁴⁴² Justice Hecht was joined by Justice Green, Justice Johnson, Justice Boyd, and Justice Devine. *Id.* at 2.

⁴⁴³ *Id.* at 3.

⁴⁴⁴ *Id.*

⁴⁴⁵ *Id.* at 5.

⁴⁴⁶ See text accompanying notes 432 and 433, *supra*.

⁴⁴⁷ *Chesapeake Exploration, L.L.C. v. Hyder*, 427 S.W.3d 472, 478 (Tex. App. – San Antonio 2014), *aff’d*, 2015 WL 3653446 (Tex. 2015).

⁴⁴⁸ 427 S.W.3d at 478.

⁴⁴⁹ *Id.* at 480.

⁴⁵⁰ *Id.*

The Texas Supreme Court affirmed the judgment of the court of appeals.⁴⁵¹ After discussing and dismissing several possible interpretations of the “cost free” language, the court essentially concluded that it should be given its plain meaning, with the result that “cost free” means free of all costs, whether production or post-production in character.⁴⁵²

Among the possible language interpretations rejected by the court was the lessee’s argument that because the overriding royalty is paid on the “gross production” from each of the burdened wells, the reference is necessarily to gross production at the well, thereby incorporating post-production costs into the calculation of the overriding royalty. The supreme court stated that the “gross production” language only fixed the volume of production on which the overriding royalty would be calculated and did not bear on whether the overriding royalty would be subject to post-production costs.⁴⁵³ In a dissent filed in conjunction with the majority opinion, Justice Brown⁴⁵⁴ disagreed with the majority’s interpretation of the “gross production” language, stating that “I read the overriding royalty clause as granting the [lessor] a percentage of production before post-production value is added and without allocating [the lessor’s] share of post-production costs to the [lessee]. I would thus hold that [the lessee] properly deducted post-production costs. . . .”⁴⁵⁵

5. Costs Deductible from Royalty.

Against the backdrop of this analysis, the Texas courts have permitted the deduction of, inter alia, the following types of taxes

and post-production expenses: (a) ad valorem, gross production, and severance taxes,⁴⁵⁶ unless the responsibility for such taxes is shifted pursuant to a tax shifting clause⁴⁵⁷; (b) costs of gathering and transportation of production from the wellhead to the point of delivery to the purchaser⁴⁵⁸; (c) costs of dehydration⁴⁵⁹; (d)

⁴⁵⁶ *Holbein v. Austral Oil Co.*, 609 F.2d 206 (5th Cir. 1980) (gross production and severance taxes); *Sheffield v. Hogg*, 124 Tex. 290, 77 S.W.2d 1021 (1934) (*ad valorem* taxes). *But see Lee M. Bass, Inc. v. Shell Western E&P, Inc.*, 957 S.W.2d 159 (Tex. App. – San Antonio 1997, *no writ*) (lease clause requiring lessee to reimburse lessor for “all production, severance, gathering, sales, excise, and similar taxes” held not to cover ad valorem taxes).

⁴⁵⁷ *E.g., Cartwright v. Cologne Production Co.*, 182 S.W.3d 438, 446 (Tex. App. – Corpus Christi — Edinburg 2006, *pet. denied*) (tax shifting clause caused the lessee to be responsible for paying production and severance taxes assessed against the royalty owners); *Chesapeake Operating, Inc. v. Denson*, 201 S.W.3d 369, 371-372 (Tex. App. – Amarillo 2006, *pet denied*) (tax shifting clause required the lessee to bear the first 2% of applicable production taxes, with the lessor and lessee to share proportionately the burden of any tax increases); *Santa Fe Energy Co. v. Baxter*, 783 S.W.2d 643, 646 (Tex. App. – Houston [14th Dist] 1989), *writ denied*); *J.M. Huber Corp. v. Santa Fe Energy Resources, Inc.*, 871 S.W.2d 842, 845-846 (Tex. App. – Houston [14th Dist] 1994, *writ denied*) (tax shifting clause requiring the lessee to pay “all taxes of every kind lawfully levied or assessed upon or against all or any part of the oil and gas ... and/or production therefrom ...” held to require the lessee to pay the windfall profits tax assessed against the lessor’s share of production). *But see Tenneco West, Inc. v. Marathon Oil Co.*, 756 F.2d 769 (9th Cir. 1985) (tax shifting clause requiring the lessee to pay all taxes “referable to any operations ... including ... the production, extraction, severance or removal of any oil” held not to cover windfall profits taxes). See 3 WILLIAMS & MEYERS, *supra* note 59, § 645.2 at 606-608.

⁴⁵⁸ *E.g., Ramming v. Natural Gas Pipeline Co. of America*, 390 F.3d 366, 375 (5th Cir. 2004); *Phillips Petroleum Co. v. Johnson*, 155 F.2d 185 (5th Cir. 1946), *cert. denied*, 329 U.S. 730, 67 S. Ct. 87 (1946); *Heritage Resources, Inc. v. NationsBank, Co-Trustee*, 939 S.W.2d 118 (Tex. 1996); *LeCuno Oil Co. v. Smith*, 306 S.W.2d 190, 193 (Tex. Civ. App.-Texarkana 1957, *writ ref’d n.r.e.*), *cert. denied*, 355 U.S. 907 (1957).

⁴⁵⁹ *Holbein v. Austral Oil Co.*, 609 F.2d 206 (5th Cir. 1980); *LeCuno Oil Co. v. Smith*, 306 S.W.2d 190, 193

⁴⁵¹ 2015 W. 3653446 at 2.

⁴⁵² *Id.* at 3-4.

⁴⁵³ *Id.* at 4.

⁴⁵⁴ Justice Brown was joined in dissent by Justice Willett, Justice Guzman, and Justice Lehrmann. *Id.* at 5.

⁴⁵⁵ *Id.* at 7.

compression costs associated with making gas deliverable into the purchaser's pipeline⁴⁶⁰; and (e) costs of treatment and processing incurred to extract impurities and liquids from the gas stream.⁴⁶¹

It is important to keep in mind the distinction between "production costs" and "marketing costs" in this context. Production costs are the expenses incurred in exploring for mineral substances and in bringing them to the surface.⁴⁶² In *Parker v. TXO Production Corp.*, the court held that costs of compression applied by TXO to increase production from the wells constituted production costs, rather than marketing costs and, consequently, were not properly chargeable to the royalty owners.⁴⁶³

In a similar vein, while the costs of treating gas for the removal of CO₂ that is native to the reservoir are clearly post-production in character,⁴⁶⁴ the issue is more complex when considered in the context of a CO₂ flood conducted as part of a tertiary

(Tex. Civ. App.-Texarkana 1957, *writ ref'd n.r.e.*), *cert. denied*, 355 U.S. 907 (1957).

⁴⁶⁰ *Martin v. Glass*, 571 F. Supp. 1406 (N.D. Tex. 1983), *aff'd without opinion*, 736 F.2d 1524 (5th Cir. 1984); *Judice v. Mewbourne Oil Co.*, 939 S.W.2d 133 (Tex. 1996); *Cartwright v. Cologne Production Co.*, 182 S.W.3d 438, 446 (Tex. App. – Corpus Christi – Edinburg 2006, *pet. denied*); *Niemeyer v. Tana Oil and Gas Corp.*, 39 S.W.3d 380, 386 (Tex. App. – Austin 2001, *pet. denied*).

⁴⁶¹ *Piney Woods Country Life School v. Shell Oil Co.*, 726 F.2d 225, 240 (5th Cir. 1984), *cert denied*, 471 U.S. 1005 (1985) (costs of processing); *French v. Occidental Permian Ltd.*, 440 S.W.3d 1, 10 (Tex. 2014) (costs of processing and non-native CO₂ removal); *Danciger Oil & Refineries, Inc. v. Hamill Drilling Co.*, 141 Tex. 153, 171 S.W.2d 321 (1943); *Blackmon v. XTO Energy, Inc.*, 276 S.W.3d 600, 604 (Tex. App. – Waco 2008, *no pet.*) (costs of amine treatment unit to reduce native CO₂ content of produced gas); *Tana Oil and Gas Corp. v. Cernosek*, 188 S.W.3d 354, 361 (Tex. App. – Austin 2006, *pet denied*) (processing and treating costs).

⁴⁶² *Parker v. TXO Production Corp.*, 716 S.W.2d 644, 648 (Tex. App.-Corpus Christi 1986, *no writ*).

⁴⁶³ *Id.*

⁴⁶⁴ See note 461 and accompanying text, *supra*.

recovery operation. In *French v. Occidental Permian Ltd.*,⁴⁶⁵ the producer, as part of the CO₂ flood operations conducted with respect to the Cogdell Canyon Reef Unit in Scurry and Kent Counties, Texas (the "CCRU"),⁴⁶⁶ purchased and injected substantial volumes of non-native CO₂ into the unitized formation, which was returned to the surface entrained in the casinghead gas produced in association with crude oil from the unit wells. A portion of the casinghead gas was reinjected into the field, as permitted by the CCRU unitization agreement, but in order to boost the CO₂ content of the reinjected gas stream and to extract additional value from the casinghead gas, the producer caused a substantial portion of the casinghead gas to be processed through two plants owned by third parties for the removal of CO₂, H₂S, and natural gas liquids (NGLs). The CO₂ and H₂S extracted by processing were then transported back to the CCRU, where such gas was reinjected into the unitized formation. As consideration for these treatment and processing services, the producer paid the processor a cash fee and allocated to the producer, as an in-kind fee, 30% of the total NGLs. Because the low heating content and high nitrogen content of the residue gas after processing rendered such gas unmarketable, the processor also retained all of the residue gas for use in its nearby electric generation facility.⁴⁶⁷

One of the two oil and gas leases included in the CCRU contains a Middleton Lease Royalty Clause (the "Fuller Lease"), while the other lease provides for royalty based on "the net proceeds from the sale" of "gasoline or other products manufactured and sold" from casinghead gas "after deducting the costs of manufacturing the same" (the "Cogdell Lease").⁴⁶⁸ Before the CO₂ flood was initiated for the CCRU, the

⁴⁶⁵ 440 S.W.3d 1 (Tex. 2014).

⁴⁶⁶ *Id.* at 2.

⁴⁶⁷ *Id.* at 5-7.

⁴⁶⁸ *Id.* at 2-3.

producer paid royalty on the casinghead gas produced from the CCRU based on the value of the NGLs extracted by processing and the residue gas, less the costs of processing and treating the gas for the removal of H₂S and nitrogen. Since the commencement of the CO₂ flood, the producer has paid royalty on the casinghead gas based on the value of the 70% of the NGLs allocated to the producer by the processor, less a proportionate share of all costs of processing and CO₂ and H₂S removal, but no royalty on the 30% of the NGLs or the residue gas retained by the processor as in-kind compensation.⁴⁶⁹

The royalty owner argued that under both of the relevant leases, except for the costs of removal of H₂S and extraction of NGLs, all costs associated with the removal of CO₂ from the casinghead gas stream should be treated as production costs borne solely by the producer and not deducted in calculating royalty.⁴⁷⁰ The producer argued that under both leases, the removal of the CO₂ was an integral part of processing the casinghead gas for the removal of NGLs and, therefore, the costs of CO₂ removal should be deductible in calculating royalty.⁴⁷¹ The Texas Supreme Court agreed with the producer, concluding that since the CCRU unitization agreement, to which the lessor was a party, gave the producer the right to process the casinghead gas and the lessor had benefited economically from the processing, all costs of processing, including the costs

⁴⁶⁹ *Id.* at 6-7. There appears to have been no disagreement among the parties concerning, in particular, how the market value at the well of the casinghead gas was determined under the Fuller Lease. With respect to that lease, the parties appear to have endorsed, and the court did not question, the use of the *Heritage Resources* net-back method of market value determination. See *French*, 400 S.W.3d at 3 nn. 5-7.

⁴⁷⁰ *Id.* at 7. As stated by the supreme court, the lessor claims “a royalty on the value of the native casinghead gas stream that was being processed at the Fuller Plant before the CO₂ flood.” *Id.*

⁴⁷¹ *Id.*

of CO₂ removal, should be treated as post-production costs deductible in calculating (a) the market value at the well of the casinghead gas under the Fuller Lease and (b) the “net proceeds from the sale” of the NGLs extracted by processing the casinghead gas under the Cogdell Lease.⁴⁷²

It is also important to keep in mind that the interpretation placed on the phrase “at the well” may narrow the scope of the costs properly deductible by a lessee in calculating royalty. Recall that, under *Middleton*, the Texas Supreme Court held that the phrase “at the well” means any place on the leased premises, and not simply at the wellhead of a well.⁴⁷³ In the case of a sale of gas delivered on the leased premises although not at the wellhead, if a lessee has installed a compressor, dehydrator, or a gathering system that is physically located on the leased premises, the lessee may wish for the royalty owner to bear his share of the costs of operating this equipment and facilities. These expenses arguably are not deductible from royalty, however, since they are incurred “at the well” within the meaning of *Middleton*, even though the expenses are incurred downstream of the actual wellhead. In *Scaggs v. Heard*,⁴⁷⁴ the federal district court, in applying a royalty provision calling for the calculation of royalty based on the amount received by the lessees at the well when the gas was sold at the well, held that the royalty owners were entitled to the applicable royalty fraction of the total proceeds of all oil and gas sold on the leased premises, and that the lessee was not entitled to deduct from royalty a proportionate part of the costs of operating a compressor located on the leased premises necessary to deliver gas into the purchaser’s pipeline at a delivery point also located on the leased premises. The

⁴⁷² *Id.* at 10.

⁴⁷³ *Exxon v. Middleton*, 613 S.W. 2d 240, 243 (Tex. 1981).

⁴⁷⁴ 172 F. Supp. 813, 817 (S.D. Tex. 1959).

language of the *Middleton* Lease Royalty Clause is sufficiently similar to that in controversy in *Scaggs* that the same result under the *Middleton* Lease Royalty Clause seems likely given appropriate facts.⁴⁷⁵

6. Basis Differentials.

As described in Section II.C of this paper,⁴⁷⁶ most domestic natural gas is marketed based on a designated index price plus or minus the applicable basis differential. A well-known treatise on the subject defines the phrase “basis differential” as follows:

The basis differential between two hubs in the pipeline network is the difference in the prices of spot gas sold in markets at the two points. When these markets are integrated, the basis differential is made up of differences in the current spot prices of gas at the origin and destination hubs, which should equal the pipeline charge for transportation of that gas from the origin to the ... point of delivery.⁴⁷⁷

⁴⁷⁵ See D. Pierce, *supra* note 2, at 15.

⁴⁷⁶ See text accompanying notes 35 through 37, *supra*.

⁴⁷⁷ Paul W. McAvoy, *The Basis Differentials on Partially Deregulated Transportation*, NATURAL GAS NETWORKS PERFORMANCE AFTER PARTIAL DEREGULATION (Ed. Paul W. McAvoy, World Scientific Publishing, Singapore 2007) (hereinafter, “*McAvoy*”). By way of example, assume that the origin point is the GAS DAILY[®] “El Paso, Permian” point in the Permian Base of West Texas, and the destination point is the GAS DAILY[®] “Henry Hub point” in Erath, Louisiana, the official delivery point for the NYMEX gas futures contract. If, on August 13, 2015, the midpoint index price at Henry Hub is \$2.915 per MMBtu and the midpoint index price at El Paso, Permian on the same day is \$2.880 per MMBtu, the actual basis differential on such day is “minus \$0.035 to Henry Hub.” See Fletcher J. Sturm, TRADING NATURAL GAS: CASH, FUTURES, OPTIONS AND SWAPS at 55 (PennWell Books

Some commentators have asked whether a basis differential, since it is a concept related to gas transportation, should be characterized as a post-production cost.⁴⁷⁸ If that were the case, a royalty clause like that in *Hyder*⁴⁷⁹ arguably would not permit the basis differential to be taken into account in calculating royalty. We are aware of no cases that have addressed this issue, but we suggest that characterizing a basis differential as a post-production cost would be an incorrect result.

The primary reason for this view is that basis differentials do not represent actual transportation costs. Basis differentials are theoretical constructs designed to describe the differences in the commodity values of gas at the origin or supply end and at the destination or market end of a pipeline. In periods of pipeline congestion creating capacity constraints, basis differentials will increase as the spot price for gas at the supply end of the pipeline decreases (because the gas is difficult or expensive to get to market); in periods of low pipeline congestion, basis differentials will shrink as the spot prices for gas at the origin and destination ends of the pipeline converge due to increased market efficiencies.⁴⁸⁰ Because of a combination of regulated tariff rates (which do not adjust to market changes as efficiently as basis does) and long-term transportation contracts that provide for negotiated rates, the actual costs of transportation do not, as a practical matter, move in lockstep with basis. Indeed, it is not uncommon, from time to time during periods of relatively flat basis,

1997); GAS DAILY[®], Vol. 32, Issue 155 (Platts/McGraw Hill Financial, August 13, 2015).

⁴⁷⁸ See, e.g., Watt, *supra* note 2, at 20-21.

⁴⁷⁹ *Chesapeake Energy, L.L.C. v. Hyder*, 427 S.W.3d 472, 476 (Tex. App. – San Antonio 2014), *aff'd*, 2015 WL 3653446 (Tex. 2015). See text accompanying note 423, *supra*.

⁴⁸⁰ See Matthew E. Oliver, Charles F. Mason, and David Finoff, *Pipeline Congestion and Basis Differentials*, JOURNAL OF REGULATORY ECONOMICS 46, No. 3, at 261-291 (2014).

for actual transportation costs from an origin point to a destination point to exceed the basis between the two points.⁴⁸¹

For these reasons, basis differentials are simply not “incurred” by pipelines in the same way that they actually incur out-of-pocket costs and expenses to provide compression, treatment, processing, or transportation services that are passed through to producer/shippers. Under the Texas cases, it seems clear that a producer must actually incur a cost or expense after gas has been produced for the cost to be characterized as a post-production cost.⁴⁸²

G. Processed Gas.

1. Background.

Processing gas for the removal of NGLs has been common practice since the earliest days of the oil and gas industry.⁴⁸³ The advent of the so-called “shale revolution” beginning in the Barnett Shale area of North

Texas in 2005, however, has dramatically increased the importance of gas processing because, with gas index prices holding relatively steady in the range of \$2.00 to \$5.00 per MMBtu since late 2008, most of the best returns on investment for producers have been found in shale gas plays rich in liquid hydrocarbons, like the Eagle Ford Shale and the Marcellus Shale.⁴⁸⁴ For example, in Texas, between 2009 and 2013, annual ethane production increased from approximately 15,000,000 barrels to approximately 280,000,000 barrels, and annual propane production increased from approximately 10,000,000 barrels to approximately 150,000,000 barrels.⁴⁸⁵ To handle this massive increase in the need for gas processing, as of the end of 2014, over seventy projects to construct new, or expand existing, processing capacity had been identified nationwide (forty of which are in Texas), with the goal of increasing U.S. processing capacity from 83 Bcf of gas per day at the end of 2014 to 95 Bcf of gas per day by 2017.⁴⁸⁶

Gas processing transactions generally take two forms. In a “service based” processing transaction, the processor does not take title to the producer’s gas at the inlet of the plant. Rather, the processor processes the producer’s gas for the removal of NGLs in consideration of the producer’s payment of a cash fee and the producer’s retention of a portion of the gas as plant and (if necessary) compressor fuel and a

⁴⁸¹ See Rusty Brazier, *Honey, I Shrunk the Basis: Spread Between Max and Min Natural Gas Prices Drops Below \$1.00*, RBN ENERGY LLC (February 16, 2012), available at <https://rbenergy.com/Honey-I-Shrunk-the-Basis>. In the example cited in this blog entry, on February 15, 2012, the spot price of gas at the supply point of CIG Rockies was \$2.49 per MMBtu, while the spot price at the market hub at Columbia Gas Transmission’s TCO Pool was \$2.57, resulting in a basis differential of minus \$0.08 per MMBtu to Columbia TCO. Actual transportation costs between those points on the same day were approximately \$0.25 per Mcf. Subject to appropriate Btu adjustments, a seller/shipper of gas from the Rockies would make \$0.08 per MMBtu on its gas sale at Columbia TCO but lose a net \$0.17 per MMBtu on the same transaction due to the higher actual transportation costs.

⁴⁸² *E.g.*, *Blackmon v. XTO Energy, Inc.*, 276 S.W.3d 600, 604 (Tex. App. – Waco 2008, *no pet.*) (“Whatever costs are incurred after production of the gas or minerals are [post-production costs] normally proportionately borne by both the operator and the royalty interest owner.”) (emphasis added)

⁴⁸³ For example, ExxonMobil’s King Ranch Gas Plant in Kingsville, Texas, began operations in 1960. See http://www.kingsvillerecord.com/news/2010-09-26/Front_Page/King_Ranch_Gas_Plant_is_celebrating_50th_birthday.html.

⁴⁸⁴ Memorandum dated July 17, 2014, prepared by the Quadrennial Energy Review Task Force Secretariat and Energy Policy and Systems Analysis Staff, U.S. Department of Energy, styled *Stakeholder Meeting on Natural Gas Transmission, Storage, and Distribution*, available at http://www.energy.gov/sites/prod/files/2014/07/f17/pitt_sburgh-germeeting-memo.pdf (hereinafter, the “2014 QER Memorandum”).

⁴⁸⁵ Matt Menchaca, *An Overview of the Past Five Years of Texas Natural Gas Processing Plant Activity* (July 29, 2014), available at <http://www.info.drillinginfo.com/tex-natural-gas-processing-activity/>.

⁴⁸⁶ 2014 QER Memorandum, *supra* note 484, at 9.

percentage of the NGLs extracted. The producer then receives the remainder of the NGLs extracted and the residue gas at the tailgate of the plant. In a “sale based” processing transaction, the producer sells its gas to the processor at the wellhead, at a central delivery point in the field, or at the inlet of the plant. The price paid by the processor is either an index price or, more commonly in recent years, a price per MMBtu equal to a percentage of the proceeds received by the processor upon its sale of the NGLs extracted from the producer’s gas and the residue gas after processing. The latter type of processing agreement is often referred to as a “percentage of proceeds” or “POP” contract.⁴⁸⁷ These different types of processing transactions have given rise to a number of royalty-related disputes.

2. “Service Based” Processing Transactions.

a. Middleton Lease Royalty Clause. The *Middleton* Lease Royalty Clause provides that royalty will be payable on gas produced from the leased premises and “used in the manufacture of gasoline or other products therefrom”, but it does not provide for a specific royalty on substances extracted from the gas stream through processing. When a *Middleton* Lease Royalty Clause is the governing royalty clause in a “service based” processing transaction, the question has frequently arisen whether royalty should be calculated based upon the value of the gas in its unprocessed state, or by reference to the prices received by the lessee for the NGLs extracted from the gas and the residue gas after processing.

At least one excellent commentary has stated that, historically, producers whose gas is processed before it is sold have accounted to royalty owners based upon the sum of the proceeds received from the sale

⁴⁸⁷ See *Bowden v. Phillips Petroleum Co.*, 247 S.W.3d 690, 708 (Tex. 2008).

of the NGLs recovered and the residue gas.⁴⁸⁸ Although some early Texas cases concluded that casinghead gas and the natural gasoline separated therefrom constitute “oil” for which royalty is payable under the oil royalty clause,⁴⁸⁹ the weight of the modern Texas cases, particularly those pertaining to gas well gas, is that a producer whose gas is processed before it is sold is not obligated to pay royalties on NGLs extracted during processing in the absence of an express provision in the applicable royalty clause obligating the lessee to do so.⁴⁹⁰

The leading case in Texas on this point is *Danciger Oil & Refineries, Inc. v. Hamill Drilling Co.*⁴⁹¹ In this case, Hamill assigned its interest in certain leases to Danciger, reserving in such assignment “an overriding royalty or mineral payment” equal to 1/24 of “all of the oil, gas, casinghead gas, and other minerals produced, saved and marketed at the prevailing market price . . .” until Hamill received \$1,000,000.⁴⁹² At the time of the assignment, the existing wells produced only “sweet gas,” for which there was no market, and Danciger, through one of its subsidiaries, constructed an absorption and distillation plant for the purpose of processing the gas for the removal of NGLs.⁴⁹³

Hamill sued Danciger for an accounting, claiming that it was entitled to be paid 1/24

⁴⁸⁸ See Seddlemeyer, “*Royalties on Processed Gas*,” 36TH ANN. INST. ON OIL & GAS L. & TAX’N 5-1, 5-16 (1985) (hereinafter, “*Seddlemeyer*”).

⁴⁸⁹ E.g., *Reynolds v. McMan Oil & Gas Co.*, 11 S.W.2d 778, 782 (Tex. Comm’n App. 1928, *judgmt approved*); *Livingston Oil Corp. v. Waggoner*, 273 S.W. 903, 906 (Tex. Civ. App.- Amarillo 1925, *writ refd*).

⁴⁹⁰ See Seddlemeyer, *supra* note 336, at 5-16 - 5-19.

⁴⁹¹ 141 Tex. 153, 171 S.W.2d 321 (1943).

⁴⁹² 171 S.W. 2d at 322.

⁴⁹³ *Id.*

of the gross receipts of all of the products manufactured from the relevant gas.⁴⁹⁴ The Texas Supreme Court, however, reversed the judgments of the district court and the court of civil appeals and held that Hamill was entitled to receive only 1/24 of the value of the gas as produced at the wellhead, as Danciger had argued.⁴⁹⁵ According to the court:

No provision was made for the processing of the products, nor for the payments to be made out of the processed products . . . The payments were to be made out of “gas . . . if, as and when produced,” and not out of its value after it had been processed into a product of higher value . . .⁴⁹⁶

In *Carter v. Exxon Corp.*,⁴⁹⁷ the Texas Court of Appeals was called upon to address a virtually identical claim against Exxon by royalty owners who had executed an oil and gas lease containing a royalty provision identical to the *Middleton Lease Royalty Clause*. According to the royalty owners, Exxon had historically failed to pay the correct amount of royalties for gas processed by Exxon for the removal of NGLs at two processing facilities owned and operated by Exxon because of Exxon’s failure to pay royalty based upon the value of the NGLs and residue gas, less processing costs.⁴⁹⁸ After determining that the applicable royalty payment standard under the lease in controversy was the market value at the well, the court, in rejecting the royalty owners’ claims, stated:

The payment provision of the leases in question provides that royalties are to be paid on the gas used for the extraction of liquids. The inclusion of the words “at the well” in the royalty provision specifies that royalties are owed for gas that is produced in its natural state, not on the components of the gas that are later extracted . . .

We further hold that the leases do not allow the market value of the gas used to manufacture liquid products to be calculated on the sales value of the liquid products. “At the well” designates the point in the gas production process where market value is to be calculated on the gas used for the extraction of liquid products. . . The liquid products valuation method advocated by appellants provides for the calculation of the market value of the gas at a post-production step in the processing procedure. The liquid products valuation method is, therefore, not permitted by the leases because it involves a determination of market value after the gas is produced.⁴⁹⁹

Exxon had paid royalties based on the maximum lawful price in effect under the

⁴⁹⁴ *Id.*

⁴⁹⁵ *Id.* at 323.

⁴⁹⁶ *Id.* at 322-23.

⁴⁹⁷ 842 S.W.2d 393 (Tex. App.-Eastland 1992, *writ denied*).

⁴⁹⁸ *Id.* at 395.

⁴⁹⁹ *Id.* at 397. Substantially similar results were reached in *Sowell v. Natural Gas Pipeline Co. of America*, 789 F.2d 1151, 1157 (5th Cir. 1986); *Phillips Petroleum Co. v. Record*, 146 F.2d 485 (5th Cir. 1944); *Maddox v. Texas Co.*, 150 F. Supp. 175 (E.D. Tex. 1957); and *Lone Star Gas Co. v. Stine*, 41 S.W.2d 48 (Tex. Comm’n App. 1931). See Maxwell, *supra* note 2, at 15-43, 15-44.

NGPA for gas committed or dedicated to interstate commerce. Since the gas processed in Exxon's plants was gas that, if sold, would have been subject to that maximum lawful price under the NGPA, the court concluded that Exxon's evidence concerning that maximum lawful price as the market value of the gas was sufficient to support the jury's findings concerning market value.⁵⁰⁰

The *Carter* court's unequivocal statement that "the liquid products valuation method is ... not permitted" under the *Middleton* Lease Royalty clause seems clear. It was also made before the Texas Supreme Court endorsed the net-back method of calculating market value royalty in *Heritage Resources*. What would be the result in *Danciger* and *Carter* if the court had applied the net-back approach? Some guidance is provided in *Piney Woods*, in which the Fifth Circuit, in the absence of comparable sales of sour gas in the relevant market area, approved a market value determination which identified the market value of sweet gas and extracted sulphur, the products derived from the treatment process, and then subtracted the costs of transportation and treatment to determine what a buyer would have paid for sour gas at the wellhead.⁵⁰¹ At least two recent Texas cases appear to have followed this approach.

In *French v. Occidental Permian Ltd.*,⁵⁰² a case involving, in part, the determination of royalty due on casinghead gas produced from a CO₂ flood unit and processed in a third party-owned processing plant,⁵⁰³ recall that the Fuller Lease included in the CCRU contained a *Middleton* Lease Royalty

Clause.⁵⁰⁴ Although the Texas Supreme Court acknowledged in a footnote that the royalty clause in the Fuller Lease was identical to the *Middleton* Lease Royalty Clause,⁵⁰⁵ the court adopted the *Heritage Resources* formulation of the net-back methodology⁵⁰⁶ as the method for determining the market value at the well of the processed casinghead gas, stating that, "The market price of the processed gas reflects the value of the unprocessed gas at the well if reasonable post-production costs are deducted . . . which may vary depending on the quality of the gas coming from the ground."⁵⁰⁷ The court devoted almost no attention to the "value" component of the royalty calculation, noting only that "[t]he only market value evidence in the case is of the NGLs and residue gas at the tailgate of the [processing] plant, after processing is complete."⁵⁰⁸ There appears to have been no disagreement among the parties about how the market value at the well of the casinghead gas was determined under the Fuller Lease, other than the appropriateness of deducting CO₂ extraction costs in the royalty calculation. Indeed, ultimately, the court held that royalty on casinghead gas produced from the CCRU and allocable to the Fuller Lease must be calculated based on the market value of the gas at the well, net of the costs of CO₂ extraction.⁵⁰⁹

⁵⁰⁰ 842 S.W.2d at 399.

⁵⁰¹ *Piney Woods Country Life School v. Shell Oil Co.*, 726 F.2d 225, 239 (5th Cir. 1984), cert. denied, 471 U.S. 1005, 105 S. Ct. 1868 (1985).

⁵⁰² 440 S.W.3d 1 (Tex. 2014).

⁵⁰³ *Id.* at 4-5. See text accompanying notes 465 through 472.

⁵⁰⁴ 440 S.W.3d at 2-3.

⁵⁰⁵ *Id.* at 3, n. 4.

⁵⁰⁶ In footnote 7, the court quoted the *Heritage Resources* test as follows: "[M]arket value at the well" may be determined by subtracting reasonable post-production marketing costs "– including the costs of transporting the gas to market and processing the gas to make it marketable" – "from the market value at the point of sale". *Id.* at 3, n. 7, citing *Heritage Res. Inc. v. NationsBank*, 939 S.W.2d 118, 122 (Tex. 1996).

⁵⁰⁷ 440 S.W.3d at 3.

⁵⁰⁸ *Id.* at 8.

⁵⁰⁹ *Id.* at 10.

Similarly, in *Commissioner of the General Land Office v. Sandridge Energy, Inc.*,⁵¹⁰ a case involving the processing of gas for the removal of native CO₂ by a third party gas processor,⁵¹¹ the El Paso Court of Appeals, applying the principles of *Heritage Resources*,⁵¹² held that, under the oil and gas leases in controversy that contained royalty clauses identical or substantially similar to the *Middleton Lease Royalty Clause*,⁵¹³ but that did not provide for a specific royalty on products extracted from the gas by processing,⁵¹⁴ a single royalty was payable only on “raw gas”, including all of its components, in its natural state as it is produced from the leased premises and measured at the wellhead, and that no separate royalty was due on CO₂ removed by processing.⁵¹⁵

It should be noted that the courts’ analyses in these cases does not change regardless of whether the gas processor is the lessee or its affiliate, as in *Danciger* and *Carter*, or an unaffiliated third party, as in *French* and *Sandridge*.

b. 4/76 Royalty Clause. As several courts have pointed out, controversy regarding whether the lessor is entitled to royalty on the NGLs and other substances

extracted from processed gas and the residue gas after processing may be avoided by the inclusion of appropriate language in the royalty clause.⁵¹⁶ Unlike the *Middleton Lease Royalty Clause*, the 4/76 Royalty Clause provides specifically that when gas produced from the leased premises is “used . . . in the manufacture of gasoline or other products”, royalty is paid based on the amounts realized, respectively, from the “sale of gasoline or other products extracted” and the “sale of residue gas, after deducting the amount used for plant fuel or compression.”⁵¹⁷ The Texas courts have consistently enforced these types of royalty clauses according to their terms.

Thus, for example, in *French*,⁵¹⁸ the Texas Supreme Court enforced the royalty clause in the Cogdell Lease – which provided for royalty based on the “net proceeds from the sale” of the products extracted from the gas by processing, less processing costs⁵¹⁹ – as written and held that royalty on the casinghead gas produced from the CCRU and allocable to the Cogdell Lease should be calculated based on the sales proceeds of the products extracted from the gas less the costs of processing, including the costs of CO₂ removal.⁵²⁰ The court of appeals reached a similar result in *Sandridge*⁵²¹ with respect to the oil and gas leases in controversy that established specific

⁵¹⁰ 454 S.W.3d 603 (Tex. App. – El Paso 2014, *pet. filed*).

⁵¹¹ See note 158 and accompanying text, *supra*.

⁵¹² 454 S.W.3d at 609 (the relevant royalty clause “functions as a ‘market value at the well’ clause, or one that pays royalty on the value of the raw gas at the wellhead, before it is transported, treated, or otherwise prepared for market”) and 611 (“Market value ‘at the well’ means the value of gas at the well, before it is transported, treated, compressed or otherwise prepared for market . . . Value at the well is already net of reasonable marketing costs.”), *citing Heritage Res., Inc. v. NationsBank*, 939 S.W.2d 118, 129-130 (Tex. 1996).

⁵¹³ 454 S.W.3d at 608, 620-21. See note 159 and accompanying text, *supra*.

⁵¹⁴ 454 S.W.3d at 611, 625. See note 160 and accompanying text, *supra*.

⁵¹⁵ 454 S.W.3d at 616, 621.

⁵¹⁶ *E.g.*, *Sowell v. Natural Gas Pipeline Co. of America*, 789 F.2d 1151, 1158 (5th Cir. 1986); *Barby v. Cabot Corp.*, 465 F.2d 11, 15 (10th Cir. 1972) (“Appellants could, if they so desired, have insisted on a contractual provision which would permit them to participate in all of the profits arising from the extraction of the liquefiable hydrocarbons . . .”).

⁵¹⁷ See text accompanying note 43, *supra*.

⁵¹⁸ *French v. Occidental Permian Ltd.*, 440 S.W.3d 1 (Tex. 2014).

⁵¹⁹ *Id.* at 2-3.

⁵²⁰ *Id.* at 9-10.

⁵²¹ *Comm’r of the General Land Office v. Sandridge Energy, Inc.*, 454 S.W.3d 603 (Tex. App. – El Paso 2014, *pet. filed*).

methods for calculating royalty on gas processed or treated in a plant.⁵²²

3. “Sale Based” Processing Transactions.

Under Texas law, royalty on gas production that is first sold and then processed by the gas purchaser for the removal of NGLs is calculated based upon the royalty payment standard applicable to the sale of the gas, and the royalty owner is not entitled to a share of the proceeds received by the gas purchaser from its sale of the NGLs extracted by processing.⁵²³

Most of the recent cases dealing with royalty issues in “sale based” processing transactions have involved wellhead sales of gas pursuant to POP contracts. For example, in *Tana Oil and Gas Corporation v. Cernosek*,⁵²⁴ a class action lawsuit in which the plaintiff royalty owners successfully achieved class certification,⁵²⁵ the lessee sold gas produced from the leased premises to a gas processor at the wellhead pursuant to a POP contract under which the lessee received a price equal to 84% “of the combined monthly sales prices of the component-plant products extracted from the raw gas, and ... the alternate market resale price for all residue gas remaining after treatment.”⁵²⁶ The gas processor then resold the gas, also at the wellhead, to a second gas processor, who actually processed the gas, for a price equal to a percentage of the “downstream monthly

sales price of the residue gas and the extracted liquids.”⁵²⁷

The four oil and gas leases in controversy contained commonly worded royalty clauses, including a 4/76 Royalty Clause, that provided for the payment of royalty on gas produced from the leased premises and sold based on the “amount realized by the lessee, computed at the mouth of the well”, the “amount realized” from the sale of the produced gas at the well, and “the net proceeds at the well received [by the lessee] from the sale ...” of such production.⁵²⁸ Each month, the lessee received, from the first gas processor under their POP contract, an amount equal to 84% of the proceeds from the sale of the extracted NGLs and the residue gas, less processing and compression costs, and paid royalty on such net amount.⁵²⁹ The royalty owners complained, however, that the lessee should pay royalty based on 100% of the post-processing NGL and residue gas sales proceeds, because the leases require the lessee to pay royalty on 100% of the wellhead production.⁵³⁰

In reversing the judgment of the district court, the Austin Court of Appeals rejected the royalty owners’ argument and held that the lessee complied with its royalty obligations by calculating royalties “based on the full amount it received from the sale of the raw gas at the well.”⁵³¹ According to the court,

[The lessee] sold raw gas at the well, before value was added by preparing the gas for market ... In exchange for its sale of 100% of the total volume of raw gas at the

⁵²² *Id.* at 620, 623. See note 162 and accompanying text, *supra*.

⁵²³ *E.g.*, *Read v. Britain*, 414 S.W.2d 483, 487 (Tex. Civ. App. – Amarillo 1967), *aff’d*, 422 S.W.2d 902 (Tex. 1967); *Lone Star Gas Co. v. Harris*, 45 S.W.2d 664, 667 (Tex. Civ. App. – Eastland 1931), *on reh’g*, 45 S.W.2d 998 (Tex. Civ. App. – Eastland 1932, *writ ref’d*).

⁵²⁴ 188 S.W.3d 354 (Tex. App. – Austin 2006, *pet. denied*).

⁵²⁵ See text accompanying notes 136 and 137, *supra*.

⁵²⁶ 188 S.W.3d at 356-357.

⁵²⁷ *Id.*

⁵²⁸ *Id.* at 357-358.

⁵²⁹ *Id.* at 357.

⁵³⁰ *Id.* at 358, 360.

⁵³¹ *Id.* at 361.

well, [the lessee] received a price equivalent to 84% of the proceeds for the processed gas ... Accordingly, by paying ... royalties on 100% of the money it actually received, [the lessee] did in fact pay royalties on 100% of the total volume of raw gas that it sold at the well.⁵³²

More recently, in *Occidental Permian Ltd. v. The Helen Jones Foundation*,⁵³³ a case involving the determination of royalty due on casinghead gas produced from a CO₂ flood unit and processed for the removal of NGLs and CO₂ in a lessee-owned processing plant,⁵³⁴ the casinghead gas was sold at the wellhead pursuant to life-of-the-processing-plant POP contracts entered into in the 1940s that were inherited by the current lessee upon its acquisition of the oil and gas leases included in the unit. Under the POP contracts, the lessee received a price for 100% of the casinghead gas equal to 50% of the proceeds from the sale of the residue gas and 33.3% of the proceeds from the sale of the NGLs attributable, in each case, to such casinghead gas.⁵³⁵ Four of the oil and gas leases provided for the payment of royalty based on the “amount realized from such sale” when gas is sold at the wells, and the other two leases provided for the payment of royalty based on “the market value in the field” of the gas.⁵³⁶

The royalty owners complained, first, that the lessee had underpaid royalties under the “amount realized” leases because it paid royalty based only on the proceeds received

under the life-of-the-plant POP contracts instead of 100% of the proceeds of the downstream sales of the extracted NGLs and residue gas, less certain post-production costs.⁵³⁷ In rejecting the royalty owners’ argument, the Amarillo Court of Appeals stated:

If the gas contracts are effective to establish that the lessee is selling the gas at the wells, so as to trigger the obligation to pay royalty on the amount realized from “such sales”, the terms of the same contracts cannot be disregarded in the determination of the amount realized from such sales.⁵³⁸

The court also rejected the royalty owners’ complaint that the lessee had failed to pay royalty at market value under the “market value in the field” leases.⁵³⁹ After citing *Vela* and *Middleton* for the proposition that market value should be determined by reference to comparable sales,⁵⁴⁰ the court concluded that the royalty owners’ expert testimony, which attempted to establish the market value at the well of the casinghead gas by tracking the percentages of NGLs and residue gas allocated to producer/gas sellers under POP contracts between 1990 and 2007,⁵⁴¹ constituted “no evidence” of market value⁵⁴² because (a) the testimony included no evidence about the values of NGLs and residue gas during such period,⁵⁴³ and (b) the expert failed to include

⁵³² *Id.* at 360-361.

⁵³³ 333 S.W.3d 392 (Tex. App. – Amarillo 2011, *pet. denied*).

⁵³⁴ For a description of the CO₂ flood operations in *Helen Jones*, see text accompanying notes 165 through 167, *supra*.

⁵³⁵ 333 S.W.3d at 396-397.

⁵³⁶ *Id.* at 396.

⁵³⁷ *Id.* at 399.

⁵³⁸ *Id.* at 400.

⁵³⁹ *Id.* at 403.

⁵⁴⁰ *Id.* at 403-404, citing *Texas Oil & Gas Corp. v. Vela*, 429 S.W.2d 866, 872 (Tex. 1968), and *Exxon Corp. v. Middleton*, 613 S.W.2d 240, 246 (Tex. 1981).

⁵⁴¹ 333 S.W.3d at 405.

⁵⁴² *Id.* at 407.

⁵⁴³ *Id.* at 405.

high-CO₂ content gas in her comparability study.⁵⁴⁴

Finally, the court rejected the royalty owners' claim that the lessee had breached the implied covenant to market by continuing to sell the casinghead gas under the old, life-of-the-processing-plant POP contracts assumed by the lessee upon its acquisition of the relevant leases.⁵⁴⁵ The court found that (a) there was no evidence that the POP contracts were unreasonable when executed by the prior lease operator; (b) there was no evidence that the lessee would have had the ability to terminate or modify the POP Contracts if it were not also the plant owner; and (c) the royalty owners failed to prove what a reasonably prudent operator would have done differently under the same or similar circumstances.⁵⁴⁶

Our final POP contract case is an example of the unintended consequences that can result when a royalty clause requiring the payment of royalty on NGLs extracted from processed gas is not carefully drafted. In *W.T. Carter & Bro. v. Oryx Energy Company*,⁵⁴⁷ the court was required to determine the proper method of royalty calculation under a lease that contained both a *Middleton* Lease Royalty Clause and an alternative provision applicable to processed gas, which provided as follows:

“(d) Lessee (itself or with a third party or parties) or any affiliate, parent, or subsidiary of Lessee shall have right but shall not be obligated to process gas produced from the leased

premises in an absorption or extraction plant, or other type plant or plants, whether similar or dissimilar, for the recovery of the liquid and/or liquefiable hydrocarbons, sulphur or other products therefrom, and if such gas is so processed, Lessor shall have and be entitled to a royalty of [the royalty fraction] of all plant products, and all other hydrocarbons, sulphur and products so extracted, separated, produced and saved from such gas⁵⁴⁸

After obtaining gas production from the lease in controversy, the lessee entered into a variation of a POP contract with an unaffiliated, third party gas processor to process such gas for the extraction of NGLs. Under the terms of the processing arrangement, title to the NGLs extracted from the gas vested in the processor upon their extraction, but title to the raw gas and the residue gas remained vested in the lessee. The lessee paid the processor for processing costs and received 70% of the net proceeds resulting from the processor's sale of the NGLs.⁵⁴⁹ The lessee argued that, since it owned no interest in the processing plant, it was not processing gas “with a third party” within the meaning of the lease, so that the quoted alternative royalty provision did not apply. As such, the lessee argued that royalty was payable under the terms of the “amount realized” section of the, *Middleton* Lease Royalty Clause on the share of the proceeds from NGL sales received by the lessee from the processor under the POP contract and on the proceeds from the sale of the residue gas.⁵⁵⁰

⁵⁴⁴ *Id.* at 406-407.

⁵⁴⁵ *Id.* at 403. A similar result was reached in *Bowden v. Phillips Petroleum Co.*, 247 S.W.3d 690, 708-709 (Tex. 2008) (with respect to plaintiff/royalty owner “Subclass 3”). See text accompanying notes 652 and 653, *infra*.

⁵⁴⁶ *Id.* at 402-403.

⁵⁴⁷ 5 S.W.3d 704 (Tex. App. – San Antonio 1999, no pet.).

⁵⁴⁸ *Id.* at 707.

⁵⁴⁹ *Id.* at 707.

⁵⁵⁰ *Id.*

The trial court granted summary judgment in favor of the lessee, but the court of appeals reversed. According to the court of appeals, given the plain, ordinary meaning of the word “with”, the lessee was engaged in a processing arrangement “with” the unaffiliated third party processor, notwithstanding that the lessee owned no interest in the processor or the processing facility. As such, the alternate royalty payment standard under the lease was applicable, and the lessee was obligated to pay royalty on the proceeds of all of the NGLs extracted from the gas produced from the leased premises, even though the lessee received only 70% of such proceeds from the processor under the POP contract.⁵⁵¹

H. Effect of Division Orders.

To complete our analysis of the basic principles governing the lessee’s royalty obligation, we now address the effect of division orders on that obligation.

1. Historical Treatment - Case Law.

Before diving into *Middleton*’s treatment of division orders, some background is appropriate. Prior to *Middleton*, the Texas courts, and the Federal courts applying Texas law, had consistently treated division orders – regardless of whether the division order purported to act as a contract of sale, passing title to the covered substance from the interest owner to the hydrocarbon purchaser, or simply as a written direction for the party obligated to make revenue distributions concerning to whom, and in what percentages, such distributions should be made – as creating a contractual relationship among the parties that (a) does not modify the terms of the underlying lease, (b) may be unilaterally revoked by the party entitled to receive payment thereunder, and (c) like the payments made and accepted thereunder, are effective,

⁵⁵¹ *Id.*

final, and binding between the parties until revoked.⁵⁵²

The leading Texas case was the 1956 Texas Supreme Court decision in *Chicago Corp. v. Wall* (“*Wall*”).⁵⁵³ The principle underlying these rules is detrimental reliance. If the purchaser or lessee who prepares the division order underpays one interest owner and overpays another interest owner in reliance upon the interest owners’ agreement to the terms of the division order, and the underpaid interest owner is not estopped by its execution of the division order from asserting a claim for underpayment against the purchaser or lessee, the lessee could have double liability for the amount of the overpayment, an unfair result.⁵⁵⁴

None of these cases considered, however, the question whether a division order would be effective and binding if the division order established a royalty payment standard different from that in effect under the relevant lease. In *Butler v. Exxon Corporation*,⁵⁵⁵ the court of civil appeals addressed this question and answered “no.” In *Butler*, although the leases provided for a market value royalty standard for gas sold “off the premises” and an amount realized royalty standard for gas sold “at the wells,” the plaintiff/royalty owners and Exxon, following first production, executed division orders that provided that settlements for “gas sold at wells or at a central point in or near the field where produced shall be based on the net proceeds at the wells.”⁵⁵⁶

⁵⁵² *E.g.*, *J.M. Huber Corp. v. Denman*, 367 F.2d 104, 110 (5th Cir. 1966); *Pan American Petroleum Corp. v. Long*, 340 F.2d 211, 223 (5th Cir. 1964); *Phillips Petroleum Co. v. Williams*, 158 F.2d 723, 727 (5th Cir. 1947); *Chicago Corp. v. Wall*, 156 Tex. 217, 293 S.W.2d 844, 847 (Tex. 1956);

⁵⁵³ 156 Tex. 217, 293 S.W.2d 844 (1956).

⁵⁵⁴ *Id.* at 846-47.

⁵⁵⁵ 559 S.W.2d 410 (Tex. Civ. App. – El Paso 1977, writ *ref’d n.r.e.*).

⁵⁵⁶ *Id.* at 412.

The original division orders were later revoked and replaced by new division orders providing for settlements in accordance with the royalty provisions of the applicable leases.⁵⁵⁷

The trial court concluded that the original division orders and the royalty distributions made pursuant thereto were binding until the division orders were revoked, but the court of civil appeals reversed the trial court's judgment on this point, holding that the plaintiff/royalty owners' acceptance of royalties pursuant to the original division orders did not estop them from claiming royalties based on the higher market value of gas during the period before the original division orders were revoked.⁵⁵⁸ In so holding, the court relied on *Craig v. Champlin Petroleum Co.*,⁵⁵⁹ a 1969 federal district court case out of Oklahoma; refused to follow the contrary results reached in *J.M. Huber Corp. v. Denman*⁵⁶⁰ and *Phillips Petroleum Co. v. Williams*⁵⁶¹ (both of which applied Texas law); and distinguished *Wall* based on the notion that, unlike *Wall*, there was no detrimental reliance by Exxon, as the lessee/payor under the original division orders, because the original division orders were executed without consideration.⁵⁶²

In *Middleton*, Sun Oil Company of Delaware, in addition to Exxon, was also a defendant. Gas produced from Sun's leases was processed off the leased premises at Union Texas Petroleum's Winnie, Texas Plant. During the period in controversy (1973-1975), Sun sold its gas production under a fixed price gas sale contract executed in 1951 and amended in 1965 that established the sales/delivery

point as the tailgate of the Winnie Plant.⁵⁶³ Sun's leases contained royalty clauses substantially identical to the *Middleton* Lease Royalty Clause.⁵⁶⁴ Sun calculated and paid royalty based on the amount received from the sale of the gas in conformity with the terms of several division orders executed by the plaintiff/royalty owners in 1952,⁵⁶⁵ which provided that royalty on processed gas would be calculated as the sum of the applicable royalty fraction of the liquids recovered by processing plus "the proceeds derived from the sale of residue gas."⁵⁶⁶ The terms of the division orders thus effectively changed the otherwise applicable "market value" royalty standard to an "amount realized" royalty standard.

The trial court concluded that: (a) the division orders in controversy did not permanently amend the applicable royalty provisions to provide, in all cases, for the payment of royalty based on the amount realized standard; (b) until withdrawn or revoked, however, the division orders were supported by consideration and, therefore, binding on the plaintiff/royalty owners; (c) the division orders were revoked by the plaintiff/royalty owners when they filed suit against Exxon and Sun on March 30, 1974; (d) all royalty payments made by Sun prior to March 30, 1974, were final and binding on the plaintiff/royalty owners; and (e) royalty payments made thereafter were not final and binding, and the plaintiff/royalty owners were entitled to recover the excess of the market value of the gas over the amount of such post-March 30, 1974 royalty payments.⁵⁶⁷

⁵⁵⁷ *Id.* at 413.

⁵⁵⁸ *Id.* at 416-17.

⁵⁵⁹ 300 F. Supp. 119 (D.C. Okla. 1969), *aff'd*, 421 F.2d 236 (10th Cir. 1970).

⁵⁶⁰ 367 F.2d 104 (5th Cir. 1966).

⁵⁶¹ 158 F.2d 723 (5th Cir. 1946).

⁵⁶² *Wall*, 559 S.W.2d at 416-17.

⁵⁶³ *Exxon Corp. v. Middleton*, 613 S.W.2d 240, 249 (Tex. 1981).

⁵⁶⁴ *Id.* at 242, 249.

⁵⁶⁵ *Id.* at 249.

⁵⁶⁶ *Middleton*, 571 S.W.2d 349, 364 (Tex. Civ. App. – Houston [14th Dist.] 1978), *rev'd in part, rev'd and remanded in part*, 613 S.W.2d 240 (Tex. 1981).

⁵⁶⁷ *Middleton*, 613 S.W.2d at 250.

Butler was clearly on the mind of the Houston Court of Civil Appeals (14th District) in *Middleton* when it considered the issues relating to Sun's division orders. After agreeing with *Wall* that Sun's division orders created a contractual relationship between Sun and the plaintiff/royalty owners,⁵⁶⁸ the court went to considerable lengths to conclude that, unlike the division orders in *Butler*, Sun's division orders were supported by consideration in the form of several reporting and record keeping obligations on the part of Sun provided for therein. The court of civil appeals concluded, however, that because Sun's division orders were supported by consideration, the division orders effectively modified the terms of the underlying leases and, therefore, could not be unilaterally revoked by the plaintiff/royalty owners.⁵⁶⁹

The Texas Supreme Court reversed the court of civil appeals judgment and held that: (a) the division orders were effective to establish the basis on which royalty payments were made; (b) the division orders were unilaterally revocable by the plaintiff/royalty owners; and (c) payments made pursuant to the division orders were final and binding on the parties until the division orders were revoked.⁵⁷⁰ In so holding, the court reaffirmed the holding in *Wall*⁵⁷¹ and then, quoting from the Fifth Circuit's opinion in *Phillips Petroleum Co. v. Williams*,⁵⁷² stated:

[U]ntil withdrawn or modified, [the division orders] constitute the precise and definite basis for payments, and payments made in accordance with them are final and binding. . . .

⁵⁶⁸ *Middleton*, 571 S.W.2d at 364.

⁵⁶⁹ *Id.* at 365.

⁵⁷⁰ *Middleton*, 613 S.W.2d at 250-51.

⁵⁷¹ *Id.* at 250.

⁵⁷² 158 F.2d 723, 727 (5th Cir. 1946).

Binding as they are, however, in respect of payments made and accepted under them, these division or transfer orders did not rewrite or supplant the lease contract. They are binding only for the time and to the extent that they have been, or are being acted on and made the basis of settlements and payments and from the time that notice is given that settlements will not be made on the basis provided in them, they cease to be binding.⁵⁷³

As such, the plaintiff/royalty owners' rights under the leases in controversy to receive royalty based on a market value standard were modified by the division orders to authorize royalty payments based on the amount realized by Sun under its long-term contract until the division orders were revoked by the filing of suit by the plaintiff/royalty owners.

Almost seven years later, the Texas Supreme Court, in *Cabot Corp. v. Brown*,⁵⁷⁴ once again held that division orders and the payments made and accepted thereunder were effective against the royalty owner until revoked, even though the division orders provided for royalty settlement based on FPC-approved rates that were lower than the current market value that otherwise would have been the basis for royalty settlement under the terms of the applicable leases, citing *Middleton* as controlling precedent. As the result of *Wall*, *Middleton*, and *Cabot*, then, producers routinely employed gas division orders to authorize royalty settlements based on the price received by the producer under the applicable gas sale contract, notwithstanding an otherwise applicable

⁵⁷³ *Middleton*, 613 S.W.2d at 250.

⁵⁷⁴ 754 S.W.2d 104, 107 (Tex. 1987).

market value royalty payment standard in the relevant lease, and to specify the post-production costs that would be borne by the royalty owner.

2. Subsequent Limitations on Middleton and Cabot.

The Texas courts have, from time to time, placed limits on the scope of the holdings in *Middleton* and *Cabot*, however. In *Gavenda v. Strata Energy, Inc.*,⁵⁷⁵ for example, the Texas Supreme Court held that, when the lessee had erroneously prepared division orders crediting certain royalty owners with only a portion of the interest to which they were entitled and then retained the underpaid royalties for its own account, the effective division orders did not bar the royalty owners' recovery from the lessee of the amount of the underpaid royalty retained by the lessee because it profited from its error. To permit the lessee to retain the benefits of its error would result in unjust enrichment.⁵⁷⁶ In so holding, the supreme court distinguished its earlier holding in *Middleton* based on two factors. First, even though the division orders in *Middleton* provided for a royalty payment standard different from that provided for in the applicable leases, Exxon could not have detrimentally relied on the division orders' representations in entering into its long-term gas contracts, since these contracts were executed long before the royalty owners had executed the division orders. More importantly, however, Exxon did not benefit from the difference in the royalty standards expressed in the division orders and the applicable leases because they paid to the royalty owners the proper royalty fraction of the proceeds received from the gas purchaser.⁵⁷⁷

⁵⁷⁵ 705 S.W.2d 690, 692-93 (Tex. 1986).

⁵⁷⁶ *Id.* at 692.

⁵⁷⁷ *Id.*

More recently, in *Heritage Resources*,⁵⁷⁸ the applicable lease expressly provided that there would be no deductions from the value of the lessor's royalty payable thereunder for transportation and several other types of post-production costs, while the division orders executed with respect to this lease authorized the deduction of these costs.⁵⁷⁹ There does not appear to have been any issue concerning the revocation of the division orders. Nevertheless, the El Paso Court of Appeals held that the royalty owners were not bound by the division orders and that the lessee was obligated to reimburse the royalty owners for improperly withheld transportation costs.⁵⁸⁰ The court's conclusion was based upon (a) the presence in the division orders of language disclaiming an intent to alter or amend the provisions of the applicable lease, and (b) a finding that the lessee profited from the "erroneous" inclusion of language in the division orders authorizing the deduction of transportation costs because the president and sole shareholder of the lessee also was the majority shareholder of the pipeline purchaser of the gas, citing *Gavenda* in support of this conclusion.⁵⁸¹

On appeal, the Texas Supreme Court, after citing *Gavenda* for the proposition that division orders are not binding when prepared in a manner that allocates payments among the interest owners in a manner different from the lease provisions and the operator retains the benefits,⁵⁸² modified the opinion of the court of appeals on the division order issue concerning the extent of the liability for underpayments of royalties by the defendant lessee.⁵⁸³ Since

⁵⁷⁸ *Heritage Res., Inc. v. NationsBank*, 895 S.W.2d 833 (Tex. App. – El Paso 1995), *rev'd*, 939 S.W.2d 118 (Tex. 1996).

⁵⁷⁹ *Heritage Res.*, 895 S.W.2d at 835, 838.

⁵⁸⁰ *Id.* at 839.

⁵⁸¹ *Id.*

⁵⁸² *Heritage Res.*, 939 S.W.2d at 123.

⁵⁸³ *Id.* at 123-24.

there were other working interest owners who benefited from the improper deduction of transportation charges from the royalties paid to the lessor who were not defendants in this case, the supreme court concluded that the defendant/lessee could be held liable only for the portion of the unpaid royalties that it had retained.⁵⁸⁴

It is difficult to know what to make of *Heritage Resources'* holdings on division orders. At first blush, *Heritage Resources* appears to represent a retreat from the principles stated in *Middleton* regarding the effect of division orders to modify the express provisions of an oil and gas lease until the division orders are revoked. The use (indeed, I would suggest, the mischaracterization) of *Gavenda*, a case dealing with the effect of a mathematical error in the calculation of the decimal interest credited to a royalty owner, as support for the court's holding in *Heritage Resources* stretches the rationale in *Gavenda* almost to the breaking point. The inclusion in the *Heritage Resources* division orders of language authorizing the deduction of post-production costs in calculating royalty appears no more "erroneous" than was the inclusion in the *Middleton* division orders of language authorizing the payment of royalty on an amount realized, rather than a market value, basis. Perhaps the disclaimer in the *Heritage Resources* division orders of any intent to alter or amend the terms of the applicable leases provides the basis for distinguishing *Middleton*, although the supreme court does not address this point.

The foregoing result seems even odder in light of the Texas Supreme Court's holding

⁵⁸⁴ *Id.* A similar result was reached in a pre-*Middleton* case, *Stanolind Oil & Gas Co. v. Terrell*, 183 S.W. 2d 743 (Tex. Civ. App.-Galveston 1944, writ *ref'd*) (division orders prepared by lessee held not to be binding, and lessee to have been unjustly enriched, when the division orders provided for the deduction of gross production taxes from the lessor's bonus, notwithstanding an expressed lease provision to the contrary).

in *Judice v. Mewbourne Oil Co.*,⁵⁸⁵ issued on the same day as *Heritage Resources*. In *Judice*, the applicable leases provided for the payment of royalty based on of a fraction of the "market value at the well of all gas produced and saved" from the leased premises,⁵⁸⁶ but the division orders executed by the plaintiff/royalty owners and the lessee provided for royalty settlement based either on "the gross proceeds realized at the well" or "the net proceeds realized at the well" by the lessee.⁵⁸⁷ After noting the parties' agreement that the division orders governed royalty settlements prior to their revocation upon the filing of suit, the court stated that "we look only to the division orders to determine [the lessee's] royalty obligation prior to the time suit was filed," citing *Middleton*.⁵⁸⁸

3. Division Order Legislation.

In 1991, the Texas legislature amended Subchapter J of Chapter 91 of the Texas Natural Resources Code, relating to "Payment for Proceeds of Sale," to add extensive provisions relating to division orders. These provisions were expressly made effective only as to "division orders and transfer orders executed after" August 26, 1991, the effective date of the amendments.⁵⁸⁹

Under the 1991 amendments to Subchapter J, as a condition for the payment of proceeds from the sale of oil and gas production to a party entitled to receive them, the party obligated to make the payment is entitled to receive a signed division order from the payee containing certain statutorily prescribed elements.⁵⁹⁰

⁵⁸⁵ *Heritage Res.*, 939 S.W.2d 133 (Tex. 1996).

⁵⁸⁶ *Id.* at 135.

⁵⁸⁷ *Id.* at 136.

⁵⁸⁸ *Id.* at 135.

⁵⁸⁹ Acts 1991, 72nd Leg. Ch. 650, §4 (eff. Aug. 26, 1991).

⁵⁹⁰ TEX. NAT. RES. CODE ANN. §91.402(c)(1) (Vernon 2014).

The term “division order” is defined as “an agreement signed by the payee directing the distribution of proceeds from the sale of” production and “directs and authorizes the payor to make payment for the products taken in accordance with the division order.”⁵⁹¹ Division orders are deemed to be binding for the time and to the extent that they have been acted on and made the basis of settlements and payments. Division orders are terminable by either party on thirty (30) days written notice, however, and, from the time that such notice is given, they cease to be binding.⁵⁹² Division orders do not amend any lease or operating agreement between an interest owner and the lessee or operator or any other contracts for the purchase of oil or gas,⁵⁹³ nor do they change or relieve the lessee’s specific expressed or implied obligations under an oil and gas lease, and any provision of a division order that contradicts a provision of an oil and gas lease is deemed to be invalid to the extent of the contradiction.⁵⁹⁴ Division orders may be used, however, to “clarify royalty settlement terms in the oil and gas lease.”⁵⁹⁵

From the standpoint of this royalty calculation analysis, the most significant provision added to Subchapter J by the 1991 amendments is the statutory definition of the term “market value.” According to Section 91.402(i):

With respect to oil and/or gas sold in the field where produced or at a gathering point in the immediate vicinity, the terms “market value,” “market price,” “prevailing price in the field,” or other such language,

when used as a basis of valuation in the oil and gas lease, shall be defined as the amount realized at the mouth of the well by the seller of such production in an arm’s-length transaction.⁵⁹⁶

The phrase “arm’s-length transaction” is not defined.

4. Analysis.

The 1991 amendments to Subchapter J do little to facilitate or clarify the use and effectiveness of division orders in Texas. On the one hand, several provisions of the 1991 amendments emphasize the absolute preeminence of the provisions of the lease over those of the division order and, indeed, invalidate any provision of a division order that contradicts the provisions of the applicable lease, a position that retreats from the principles in *Middleton* and *Cabot* but that is consistent with the holding in *Heritage Resources*. On the other hand, the 1991 amendments incorporate the case law principle of the binding nature of division orders as the basis of royalty settlements and payments until revoked and appear to embrace *Middleton* and *Cabot* by purporting to convert statutorily the market value standard in conventional oil and gas leases to an amount realized standard.

The Texas courts have not yet addressed any of these inconsistencies.⁵⁹⁷ Some commentators have suggested that the inconsistency presented by the statutory definition of “market value” should not, in

⁵⁹¹ *Id.* at §91.401(3).

⁵⁹² *Id.* at §91.402(g).

⁵⁹³ *Id.* at §91.402(c)(2).

⁵⁹⁴ *Id.* at §91.402(h).

⁵⁹⁵ *Id.* at §91.402(i).

⁵⁹⁶ *Id.* at §91.402(i).

⁵⁹⁷ In *Yzaguirre v. KCS Res., Inc.*, 53 S.W.3d 368 (Tex. 2001), the plaintiffs apparently cited Section 91.402(i) of the Texas Natural Resources Code in support of their argument that royalty should be paid on the basis of the proceeds from the Tennessee Contract. In a footnote, the Texas Supreme Court stated, “The Royalty Owners point out that the statute is consistent with their argument, but they do not argue that it controls our analysis of their 1973 lease.” *Yzaguirre*, 53 S.W.3d at 373 n.3.

fact, be read to be applicable to oil and gas leases, notwithstanding the expressed language of Section 91.402(i) to that effect, but instead should be limited in its applicability to post-August 26, 1991 division orders, given the overall context of the statute.⁵⁹⁸ The Arkansas Supreme Court followed this approach in interpreting a similar statute, holding that the statute did not have the effect of a blanket lease amendment that converted either a market value or a fixed price royalty payment standard into an amount realized payment standard.⁵⁹⁹

Assuming that to be the case, Sections 91.402(h) and 91.402(i) arguably permit a post-August 26, 1991 division order to “clarify” the meaning of “market value” in leases that do not otherwise define the term without actually amending the underlying lease, with the result that the case law definition of “market value” established in *Vela*, *Middleton*, *Heritage Resources*, and *Yzaguirre* is ignored and the “amount realized at the mouth of the well” standard articulated in the statute is substituted therefor.⁶⁰⁰ Whether such a result benefits the lessee or the royalty owner depends, of course, on whether the gas market is one of rising or declining prices. Regardless, however, at least on the issue of how royalty settlements are calculated (which, I suggest, is the most important issue addressed in a division order), it seems that 1991 amendments to Subchapter J signal a statutory return to the principles stated in *Middleton* and *Cabot* regarding the effectiveness of division orders to modify the otherwise-applicable royalty payment standard in the applicable oil and gas lease.

⁵⁹⁸ *E.g.*, 1 *Smith & Weaver*, *supra* note 155, § 4.6.E at 195-2; *Hosey*, *supra* note 2, at 12.

⁵⁹⁹ *Hillard v. Stephens*, 637 S.W.2d 581 (Ark. 1982).

⁶⁰⁰ See *Hosey*, *supra* note 2, at 12, 14.

IV. OF MARKETING AFFILIATES, SHAM SALES, AND “WASPS”.

A. Introduction.

Producer gas marketing affiliates have been lightning rods in the relationship between producers and royalty owners for decades. From the perspective of the independent producer,⁶⁰¹ the establishment of one or more gas marketing affiliates – i.e., gathering companies, gas processors, gas and NGL marketers, intrastate and NGL transportation pipelines – offers many advantages: (a) it permits the producer to capture for itself margins and costs that would otherwise be captured by unaffiliated midstream companies, pipelines, or marketers; (b) it provides the producer better control over its gas supply; (c) in some cases, it permits producers to conduct third party gas purchase, gathering, processing, transportation, or other midstream business that provides to the producer access to different markets with larger volumes of gas at higher prices than would otherwise be available to the producer acting individually; and (d) it allows the producer to limit the exposure of its core oil and gas producing assets to the potential liabilities and credit risks associated with other midstream and marketing lines of business.⁶⁰²

⁶⁰¹ The major integrated oil and gas companies, of course, often have hundreds of subsidiaries and other affiliates engaged in many different lines of business. For example, in the SEC Form 10-K filed by ExxonMobil Corporation for the fiscal year ended December 31, 2014, ExxonMobil lists, among four pages of subsidiaries, a diverse group of midstream subsidiaries, including Barnett Gathering, LLC, Cross Timbers Energy Services, Inc., ExxonMobil Gas Marketing Europe Limited, ExxonMobil Pipeline Company, ExxonMobil Sales and Supply LLC, Mountain Gathering, LLC, Trend Gathering & Treating, LLC, and Wolverine Pipe Line Company. See <http://www.sec.gov/Archives/edgar/data/34088/00003408815000013/xom10k2014.htm>.

⁶⁰² See *Hardwick and Hayes*, *supra* note 37, at 11-59; *Pearson I*, *supra* note 3, at 62.

From the perspective of many royalty owners, of course, gas marketing affiliates are little more than vehicles to permit producers to maximize profits from the sale of their production while minimizing their royalty obligations. According to this line of argument, if a producer sells gas to a marketing affiliate at a price that allows the marketing affiliate to resell the gas at a profit, but pays royalty on the original price received from the marketing affiliate, the producer deprives the royalty owner of its rightful interest in production from the leased premises.⁶⁰³ As the result, much of the producer/royalty owner litigation of the past thirty years has emanated from producer marketing affiliate transactions.

Despite the skepticism of some commentators,⁶⁰⁴ however, the use of producer marketing affiliates has not died out. In Texas, such transactions may have been declared “inherently suspect”, but they have never been declared *per se* fraudulent. Indeed, today, many producer marketing affiliates appear to be thriving. A review of some of the recent marketing affiliate cases may demonstrate why.

B. Marketing Covenant and Sham Sale Cases.

Most of the marketing affiliate cases involve royalty owner claims based on the alleged breach by the producer of the implied covenant to market or an amalgam of arguments different from, but related to, implied marketing covenant claims that may be referred to generically as the “sham sale” argument. The implied marketing covenant argument is, essentially, that by selling gas to its marketing affiliate but not accounting to the royalty owners based on the higher resale price received for the gas by the affiliate, the producer has failed to market the gas for the best price reasonably obtainable. Pursuant to the sham sale

argument, the initial sale by the producer to the affiliated purchaser is a sham sale designed to deprive the royalty owner of its rightful share of production which should be disregarded, and the true sale triggering the obligation to pay royalty takes place when the marketing affiliate resells the gas. This argument is premised on the disregard of the corporate separateness of the producer and its marketing affiliate⁶⁰⁵ and, in some cases, upon allegations of fraud.

1. The “Alter Ego” Cases: *Hagen, Parker, and Long Trusts.*

a. *Hagen.* The seminal Texas case relating to marketing affiliate transactions is *Texas Oil & Gas Corp. v. Hagen.*⁶⁰⁶ In *Hagen*, gas produced from three units was sold at the wellhead by the operator to a subsidiary pipeline company under gas sales contracts providing for a specified sales price. From that point, the pipeline subsidiary transported, dehydrated, and

⁶⁰⁵ Generally, the corporate fiction may be disregarded, even though corporate formalities have been observed and corporate and individual property have been kept separately, when the corporate form has been used as part of a basically unfair device to achieve an inequitable result. *Castleberry v. Branscum*, 721 S.W.2d 270, 271 (Tex. 1986); *Bell Oil & Gas Co. v. Allied Chemical Corp.*, 431 S.W.2d 336, 340 (Tex. 1968). There exist a number of separate and distinct bases upon which the corporate fiction may be disregarded, including: (a) the use of the corporate fiction as a means of perpetrating fraud; (b) the organization and operation of a corporation as a mere tool or business conduit of another corporation (also known as “alter ego”); (c) the use of the corporate fiction as a means to evade an existing legal obligation; (d) the use of the corporate fiction to achieve or perpetrate monopoly; (e) the use of the corporate fiction to circumvent a statute; and (f) the reliance on the corporate fiction as protection from a crime or as justification for a wrongful action. *Castleberry*, 721 S.W.2d at 272; *Pacific American Gasoline Co. of Texas v. Miller*, 76 S.W.2d 833, 851 (Tex. Civ. App. – Amarillo 1934, writ *ref'd*); *Gulf Oil Corp. v. State*, 360 P.2d 933, 936 (Okla. 1961).

⁶⁰⁶ 683 S.W.2d 24 (Tex. App.-Texarkana 1984), *aff'd in part and rev'd in part*, 31 Tex. Sup. Ct. J. 140 (Tex. 1987), *judgmt and op. of Tex. Sup. withdrawn, judgmt of Tex. Civ. App. set aside, motion for reh. and cause dismissed as moot*, 760 S.W. 2d 960 (Tex. 1988).

⁶⁰³ See Pearson, *supra* note 3, at 62.

⁶⁰⁴ See, e.g., Pezold, *supra* note 2, at 53.

processed the gas for the removal of H₂S and CO₂. The residue gas was then sold to end users at delivery points substantial distances from the leased premises at resale prices that were historically \$0.15 per Mcf higher than the first sale price provided for in the contracts between the producer and its pipeline subsidiary.⁶⁰⁷

Based upon its sale of gas on the leased premises to its pipeline subsidiary, the operator treated the gas as being “sold at the wells” within the meaning of the royalty clauses in the applicable oil and gas leases and, accordingly, accounted to the royalty owners based upon the amount realized from its gas sales to its pipeline subsidiary. The operator did not, however, account to the royalty owners for royalty on the sulphur extracted by processing.⁶⁰⁸

The royalty owners filed suit against the operator for improper payment of royalties, alleging three alternative theories of recovery: (i) fraudulent misrepresentation and concealment; (ii) breach of contract; and (iii) failure to market gas with good faith and reasonable diligence. The trial court rendered judgment in favor of the royalty owners on all three theories of recovery.⁶⁰⁹ According to the marketing claim, the royalty owners argued that the affiliate marketing transaction between the operator and its pipeline subsidiary constituted a failure by the operator to act in good faith in its obligation to market gas for the highest price reasonably obtainable.⁶¹⁰ The Texarkana Court of Appeals agreed, stating that the operator had violated its relationship of highest good faith or best good faith with its lessors by failing to disclose to the lessors the facts concerning the sales of gas to, and its relationship with, its pipeline subsidiary and in arranging a

sham sale in order to deprive the royalty owners of their rightful royalties.⁶¹¹

The Texas Supreme Court rejected the court of appeals’ adoption of the “highest good faith” or “the best of good faith” as the standard of performance for a lessee under the implied covenant to market, concluding instead that the proper standard was that of the reasonably prudent operator.⁶¹² Nevertheless, the supreme court concluded that, based upon the reasonably prudent operator standard, the operator failed to act as a reasonably prudent operator would have acted under the same or similar circumstances. Apparently concluding that the operator, by virtue of its affiliate relationship with its pipeline subsidiary, should have negotiated a more advantageous gas marketing arrangement for itself and its royalty owners, the court concluded that the reasonably prudent operator standard required the operator to have obtained from its pipeline subsidiary the right for itself and its lessors to receive sulfur royalties and the right to renegotiate the contract price if the market value of the gas increased.⁶¹³

The court of appeals also concluded that the operator had entered into a sham sale of gas with its pipeline subsidiary.⁶¹⁴ According to the court of appeals, “By proof that [the pipeline subsidiary], in this situation, was merely the alter ego of its

⁶⁰⁷ 683 S.W.2d at 27.

⁶⁰⁸ *Id.*

⁶⁰⁹ *Id.*

⁶¹⁰ *Id.* at 28.

⁶¹¹ *Id.* at 29.

⁶¹² 31 Tex. Sup. Ct. J. at 141-42.

⁶¹³ *Id.* at 142. It has never been clear to this author how the gas sale contract between the operator and its pipeline subsidiary would be structured to secure sulfur royalties for the lessors since the lessors’ royalty rights are defined by the terms of the oil and gas lease. Perhaps the supreme court was suggesting that the operator and its pipeline subsidiary should have moved the point of sale off the leased premises, so that the “market value at the well” royalty standard would have been in effect under the leases.

⁶¹⁴ *Hagen*, 683 S.W.2d at 28.

parent [the operator],⁶¹⁵ the district court could disregard the purported sale at the wells and find that the true sale was off premises at the [end users'] plants."⁶¹⁶

⁶¹⁵ *Alter ego* applies when there is such unity between a corporation and its shareholders that the separateness of the corporation has ceased and holding only the corporation liable would result in injustice. *First National Bank in Canyon v. Campbell*, 134 Tex. 112, 132 S.W.2d 100, 103 (1939). The existence of *alter ego* is shown from the total dealings of the corporation and shareholder, including: (a) the degree to which corporate formalities have been followed and corporate and individual property have been kept separately; (b) the amount of financial interest, ownership, and control that the shareholder maintains over the corporation; and (c) whether the corporation has been used for the individual purposes of the shareholder. *Castleberry v. Branscum*, 721 S.W.2d 270, 272 (Tex. 1986); *Lucas v. Texas Industries, Inc.*, 696 S.W.2d 372, 374 (Tex. 1984); *Stewart & Stevenson Services, Inc. v. Serv-Tech, Inc.*, 879 S.W.2d 89, 108 (Tex. App. - Houston [14th Dist.] 1994, writ denied).

⁶¹⁶ *Id.* The United States Court of Appeals for the Fifth Circuit reached a similar conclusion in *Piney Woods Country Life School v. Shell Oil Co.*, 726 F.2d 225 (5th Cir. 1984), cert. denied, 471 U.S. 1005 (1985). In *Piney Woods*, which was decided applying Mississippi law, the Fifth Circuit refused to honor what appeared to be a sale of gas "at the well" as the event triggering the obligation to pay royalty based upon other terms of the gas marketing arrangement. In that case, the leases in question contained *Middleton* Lease Royalty Clauses. The gas produced from the leases required processing for the removal of the H₂S before being marketable. Shell, as lessee, processed the gas itself and resold the residue gas to two gas purchasers. Because the gas sales contracts provided that title to the unprocessed sour gas passed to the gas purchasers in the field subject to Shell's processing rights, Shell accounted to the royalty owners based upon the actual revenues received from the sale of the processed sweet gas and the elemental sulfur removed from the H₂S during processing, less the costs of processing. *Piney Woods*, 726 F.2d at 229.

Because the price paid for the gas under the gas sales contracts was calculated by reference only to the amount of sweet gas delivered after processing, and because both contracts recited that the sales price included substantial consideration for processing and provided for Shell's assumption of the risk of loss during transportation, the Fifth Circuit reversed the district court's judgment in favor of Shell and held that the sale of gas did not take place at the wells, but at the point of redelivery of the sweet gas to the purchasers after processing. As a result, the

The court noted that the fact that a subsidiary is wholly owned by, and shares its management with, the parent does not, alone, justify disregarding the corporate entity of the subsidiary. The court continued by stating, however, that there was ample evidence to support a conclusion that the operator's pipeline subsidiary was simply a name or conduit through which the operator conducted its business. The factors identified by the court of appeals are worth noting:

Both companies have the same officers, directors, and office and field personnel. [The operator] directly paid all of the payroll and directly controlled all of [the pipeline subsidiary's] business functions, including expenses, income, and capital expenditures. The only separation was by interoffice chargeback accounting. Both companies filed consolidated income tax returns, a single SEC registration and financial statement, and property in the name of [the pipeline subsidiary] was included in an [operator] mortgage to a New York bank. All benefits earned by [the pipeline subsidiary] are direct benefits and accounts realized by [the operator] including income from the sale of sulphur from the gas in question. [The operator] owned all of [the pipeline subsidiary's] stock

court held that royalty should have been calculated by reference to the market value standard. *Id.* at 231-33. In so holding, the Fifth Circuit distinguished *Middleton* based upon the fact that the gas in controversy in *Middleton* was placed in the purchaser's control at the time title passed, while in the present case, Shell retained extensive control and risk with respect to the gas through the time of its redelivery at the tailgate of the sulphur extraction plant. *Id.* at 230.

and acted as its representative for the gas sales agreements with [the end users].⁶¹⁷

Based upon these conclusions, the court held that the royalty owners were entitled to receive royalties based upon the market value of the residue gas at the point of delivery to the end users, less the reasonable costs of transportation and processing. In addition, because the real sale of gas took place at the inlets of the end users plants, the royalty owners were also entitled to receive royalty on the sulphur extracted from the gas and sold by the pipeline subsidiary.⁶¹⁸

Because the Texas Supreme Court substantially disposed of the case based upon its holding concerning the operator's alleged breach of the implied covenant to market, the court elected not to express an opinion about the correctness of the court of appeals' holding on the issue of the *alter ego* relationship of the operator and its pipeline subsidiary.⁶¹⁹ Nevertheless, in holding that the operator had, in fact, breached its implied covenant to market gas by failing to secure "for itself and its lessors the right to receive sulfur royalties" and to reserve "the right to renegotiate the contract price payable by [the pipeline subsidiary] should the market value of the gas escalate,"⁶²⁰ the supreme court appears to have treated the wellhead sales from the operator to its pipeline subsidiary as the sales triggering the obligation to pay royalty, notwithstanding the parent-subsidary relationship of the parties.

As most veteran Texas oil and gas practitioners are aware, the Texas Supreme Court, on December 14, 1988, withdrew its original judgment and opinion of

December 16, 1987, reported in 31 Tex. Sup. Ct. J. 140, and vacated the judgment of the court of appeals.⁶²¹ The supreme court does not appear to have withdrawn the opinion of the court of appeals, however. The issuance and publication of the supreme court's original opinion in the Texas Supreme Court Journal, however, has substantially eliminated any remaining precedential value that the court of appeals' opinion may have had concerning the points as to which the supreme court ordered reversal.⁶²²

b. Parker. In *Parker v. TXO Production Corp.*,⁶²³ on the other hand, decided two years after the court of appeals' decision in *Hagen*, the Corpus Christi Court of Appeals reached a different result in a case involving similar facts. In that case, the same operator, as lessee, entered into a gas sales contract with its pipeline subsidiary and thereafter assigned its interest in the leases to its wholly owned production subsidiary.⁶²⁴ Under the gas sales contract, the pipeline subsidiary charged the production subsidiary a compression fee of 5% of the gross proceeds from the sale of the gas, which effectively reduced the proceeds received by the production subsidiary to only 95% of the market value of the gas.⁶²⁵ The royalty owners complained that the lessee, by agreeing to the 5% compression charge, breached its implied covenant to exercise good faith in marketing the gas and that the contract with the pipeline subsidiary was not negotiated at arm's length.

The court of appeals affirmed the district court judgment in favor of the lessee and its pipeline subsidiary on the implied marketing

⁶¹⁷ *Id.*

⁶¹⁸ *Id.* at 29.

⁶¹⁹ *Hagen*, 31 Tex. Sup. Ct. J. at 141.

⁶²⁰ *Id.* at 142.

⁶²¹ *Hagen*, 760 S.W.2d 960 (Tex. 1988).

⁶²² See *Hurd Enterprises, Ltd. v. Bruni*, 828 S.W.2d 101, 112 (Tex. App.-San Antonio 1992, writ denied).

⁶²³ 716 S.W.2d 644 (Tex. App. – Corpus Christi 1986, no writ)

⁶²⁴ *Id.* at 645.

⁶²⁵ *Id.* at 645-46.

covenant issue. Although the court acknowledged that the affiliate marketing transaction between the lessee and its pipeline subsidiary was “inherently suspect,”⁶²⁶ the court, in applying the reasonably prudent operator standard, stated that the existence of the compression fee paid by the lessee and its production subsidiary to the lessee’s pipeline subsidiary did not alone constitute a breach of the implied covenant to market.⁶²⁷ Based upon evidence at trial that the properties committed to the gas sales contract were subject to drainage by another’s property, the pipeline subsidiary’s capability of handling large amounts of gas on short notice, and its purchase of substantially greater volumes of gas from other, unaffiliated sellers in the region on terms substantially similar to its contract with the lessee, the court concluded that the lessee had acted in good faith and as a reasonably prudent operator in marketing the gas.⁶²⁸

Like the royalty owners in *Hagen*, the royalty owners in *Parker* argued on appeal that the trial court should have pierced the corporate veils of the lessee and its production subsidiary and concluded that the sale of gas to the pipeline subsidiary was a sham transaction, collusive, and without arm’s length bargaining.⁶²⁹ After reviewing in detail the court of appeals’ decision and rationale concerning the sham sale argument in *Hagen*, the *Parker* court concluded that there was no evidence to support such a conclusion in the present case. According to the court:

While there is evidence that the corporations involved herein do have some of the same directors, but there is no evidence that [the lessee] treated [its pipeline

subsidiary] as anything but an independent company. We find the facts of *Hagen* to be distinguishable. . . .⁶³⁰

The different results reached by the courts of appeals in *Hagen* and *Parker* are obviously difficult to reconcile. Although the two court of appeals decisions were rendered only two years apart, the *Parker* court apparently found no evidence of the substantial overlap of management and accounting functions between the lessee and its pipeline subsidiary and the substantial control of the pipeline subsidiary exercised by the lessee that the *Hagen* court found dispositive on the sham sale issue. The only relevant factual distinction that we can identify is that, in *Parker*, the lessee assigned the relevant leases to its production subsidiary, with the result that the future administration of the gas contracts in question was conducted between affiliates (the production subsidiary and the pipeline subsidiary) having the same parent (the lessee), rather than between a parent (the lessee) and subsidiary (its pipeline subsidiary), as was the case in *Hagen*. Given the subsequent procedural history of *Hagen*, *Parker* presumably represents the better precedent.

c. Long Trusts. The Texarkana Court of Appeals found the existence of a sham sale in transactions involving the operator and non-operators under a joint operating agreement in *Atlantic Richfield Co. v. The Long Trusts*.⁶³¹ In that case, Henderson Clay Products (“HCP”) and the Long Trusts were the owners of working interests in various gas wells drilled during the early 1980’s. HCP sold its share of gas produced from such wells to its wholly-owned pipeline subsidiary, and the pipeline subsidiary sold the gas to a gas utility at a price equal to the

⁶²⁶ *Id.* at 646.

⁶²⁷ *Id.* at 646.

⁶²⁸ *Id.* at 647.

⁶²⁹ *Hagen*, 31 Tex. Sup. Ct. J. at 141.

⁶³⁰ *Id.* at 647-48.

⁶³¹ 860 S.W.2d 439 (Tex. App. – Texarkana 1993, writ denied).

price paid by the pipeline subsidiary for the first sale of the gas, plus an additional operations fee.⁶³² Subsequently, Atlantic Richfield Company (“ARCO”) succeeded to the interest in the relevant wells of HCP. ARCO, as operator, and the Long Trusts, as non-operator, were parties to a joint operating agreement (the “Operating Agreement”) that provided that, if any party failed to take in kind or separately dispose of its proportionate share of production from the contract area, the operator would have the right, but not the obligation, either to purchase the non-taking party’s oil and gas or sell it to others for the account of the non-taking party at the best price obtainable in the area. In the absence of gas marketing arrangements by the Long Trusts, ARCO disposed of the Long Trusts’ share of gas production from the contract area pursuant to the foregoing provisions of the Operating Agreement.⁶³³

Pursuant to the settlement of a take-or-pay lawsuit in the early 1980’s, the gas utility and the pipeline subsidiary amended their contract to increase the volumes of gas taken by the gas utility under the contract at a new, lower price. ARCO and the pipeline subsidiary executed a corresponding amendment to their contract. Even with this price reduction, the contract price payable for gas sold under such contracts remained substantially above the spot market price for gas.⁶³⁴

The court of appeals rejected the Long Trusts’ argument that ARCO, acting through its pipeline subsidiary, violated the terms of the Operating Agreement by negotiating a reduction in the price paid for gas under the pipeline subsidiary-gas utility contract, under which the Long Trusts’ gas also was sold.⁶³⁵ Nevertheless, the court concluded that, as a result of ARCO’s sales of gas on

behalf of the Long Trusts, there existed a principal-agent relationship between those parties pursuant to which ARCO owed the Long Trusts a duty “to account for the monies received for selling its gas, to avoid conflicts of interest, and not to act as an adverse party in its capacity as the seller of its gas.”⁶³⁶

The court distinguished the principal-agent relationship of ARCO and the Long Trusts in the present case from the lesser duty of simple good faith owed by a lessee to a royalty owner under the implied covenant to market. As the result of the higher standard of duty imposed on ARCO by its principal-agent relationship with the Long Trusts, however, together with the court’s finding that the pipeline subsidiary was the *alter ego* of ARCO, the court of appeals held ARCO liable to the Long Trusts for the difference between the price received by the pipeline subsidiary upon the resale of gas to the gas utility and the price paid by the pipeline subsidiary to ARCO for the first sale of such gas.⁶³⁷

The court of appeals’ opinion does not set out the details of ARCO’s relationship with the pipeline subsidiary. It is noteworthy, however, that neither ARCO nor the pipeline subsidiary directly challenged the jury’s finding on this point, instead basing their appeals on procedural grounds relating to the manner in which the question was submitted to the jury, which points were rejected.⁶³⁸

The court, without elaboration, also upheld the jury finding that ARCO’s failure properly to account to the Long Trusts for proceeds from the sale of the Long Trusts’ gas was intentional, and that ARCO had utilized the pipeline subsidiary as a sham to perpetrate a fraud on the Long Trusts. According to the court, that finding of actual fraud

⁶³² *Id.* at 442.

⁶³³ *Id.* at 443.

⁶³⁴ *Id.*

⁶³⁵ *Id.* at 444.

⁶³⁶ *Id.* at 445.

⁶³⁷ *Id.*

⁶³⁸ *Id.* at 445-46.

supported the piercing of the corporate veil.⁶³⁹

2. The Class Action Lawsuits.

The class action royalty litigation of the late 1990s and early 2000s arose almost exclusively out of royalty owner claims for underpayment of royalties resulting from producer/marketing affiliate transactions. The “UP” cases – *Union Pacific Resources Group, Inc. v. Hankins*⁶⁴⁰ and *Union Pacific Resources Group, Inc. v. Neinast*⁶⁴¹ -- demonstrate a typical fact pattern. In both cases, the lessee sold gas produced from its leases to its gas marketing affiliate at specified index prices and paid royalty based on the proceeds from such sales. The marketing subsidiary then resold the gas to unaffiliated, third party royalty purchasers at different and usually higher index prices.⁶⁴²

The royalty owners argued that, by paying royalty based on the price received by the lessee in its sale to its marketing affiliate rather than the higher resale price received by the marketing affiliate, the lessee breached its obligation under the implied covenant to market to obtain the best price reasonably obtainable.⁶⁴³ In *Hankins*, the royalty owners also objected to marketing fees charged to the lessee by its marketing affiliate and stated claims based on *alter ego* and sham to perpetrate a fraud.⁶⁴⁴ In neither case, however, did the court reach the substance of the royalty owner’s claims. In both cases, the courts refused to certify the plaintiff/royalty owners’ class because of lack of “commonality”, concluding that under *Yzaguirre*, the implied covenant to market

applied only to leases providing for royalty based on “proceeds from the sale” or the “amount realized from the sale”, but not based on “the market value at the well.”⁶⁴⁵

Another class action royalty case, *Bowden v. Phillips Petroleum Co.*,⁶⁴⁶ involved three different classes of plaintiff/royalty owners, two of which were based on implied marketing covenant claims arising out of producer/marketing affiliate transactions.⁶⁴⁷

⁶⁴⁵ 111 S.W.3d at 74-75; 67 S.W.3d at 283-284; citing, in each case, *Yzaguirre v. KCS Resources, Inc.*, 53 S.W.3d 368 (Tex. 2001). See text accompanying notes 330 through 338, *supra*.

⁶⁴⁶ 247 S.W.3d 690 (Tex. 2008).

⁶⁴⁷ *Bowden* “Subclass 2” had been decertified by the court of appeals due to the predominance of individual issues. *Id.* at 694. This class consisted of royalty owners whose royalties were calculated under gas royalty agreements (“GRAs”) that provided for the payment of royalty on gas produced from the leased premises based on a defined weighted average price multiplied by the total volume of such gas production. *Id.* at 702-703. The lessee transported the gas a substantial distance to an affiliate-owned processing plant where the gas was processed for the removal of NGLs. *Id.* at 703. The royalty owners complained that the lessee paid royalty based only on the weighted average sale prices for dry residue gas, rather than weighted average prices that include both NGL and residue gas, which average prices would better represent the value of wet gas before processing and, in so doing, breached the GRAs. *Id.* at 704. The Texas Supreme Court concluded that nothing in the language of the GRAs evidenced an intent to give the royalty owners the benefit of the value added by processing. *Id.* at 706-707. Consequently, the supreme court held that the court of appeals erred in decertifying the class, stating that the GRAs were unambiguous and would be construed classwide for royalty owners who executed substantially similar GRAs. *Id.* *Bowden* Subclass 2 returned to the Texas Supreme Court in *Phillips Petroleum Co. v. Yarbrough*, 405 S.W.3d 70 (Tex. 2013). On remand to the district court after *Bowden*, the Subclass 2 royalty owners added a claim alleging that the lessee’s royalty calculation practices breached the implied covenant to market. *Id.* at 72. In an extremely procedurally complex opinion, the Texas Supreme Court concluded that the addition of the marketing covenant claims raised new concerns about *res judicata*, predominance, and typicality issues that were not “rigorously” considered by the district court and held that the case should be remanded to the district court for further proceedings. *Id.* at 79-81.

⁶³⁹ *Id.* at 446.

⁶⁴⁰ 111 S.W.3d 69 (Tex. 2003).

⁶⁴¹ 67 S.W.3d 275 (Tex. App. – Houston [1st Dist.] 2002, *no pet.*).

⁶⁴² 111 S.W.3d at 70; 67 S.W.3d at 279.

⁶⁴³ *Id.*

⁶⁴⁴ 111 S.W.3d at 73-74.

The claims of *Bowden* Subclass 1 were virtually identical to those of the plaintiff/royalty owners in *Hankins*, except that the oil and gas leases in controversy contained only “proceeds” or “amount realized” royalty clauses.⁶⁴⁸ Notwithstanding the absence of “market value at the well” royalty clauses in the Subclass 1 oil and gas leases, the Texas Supreme Court refused to certify Subclass 1 because individual issues predominated in the class, noting that (a) some of the leases contained express marketing obligations, so that the implied covenant to market did not universally apply and (b) the royalty owners failed to provide class-wide evidence that the lessee had failed diligently to market the gas and obtain a reasonable price for the class of lessors.⁶⁴⁹ In so holding, the supreme court indicated that the mere fact that the lessee’s marketing affiliate resold the gas for a price higher than it paid the lessee to buy the gas at the wellhead was not sufficient to establish a breach of the implied covenant to market.⁶⁵⁰ Continuing in a footnote, the court stated:

For example, if a class produced evidence that wells substantially identical to the class wells were being marketed at the wellhead to third parties for a greater price than [the lessee] was receiving, such evidence might satisfy the predominance requirement. Or if a class offered evidence that [the lessee] was artificially lowering the prices it charged [its gas marketing affiliate] for gas sales across the board or that [the lessee] was systematically miscalculating the royalty payments, such claims might

⁶⁴⁸ *Id.* at 695.

⁶⁴⁹ *Id.* at 701-702.

⁶⁵⁰ *Id.* at 702.

be more susceptible to certification.⁶⁵¹

Bowden’s “Subclass 3” royalty owners complained that, in a series of transactions in which the lessee sold its gas to an affiliated gas processor under POP contracts that allocated to the processor 20% of the NGLs extracted by processing, the 20% allocation of NGLs to the affiliated gas processor constituted an “excessive”, “unreasonable and fraudulent” post-production fee for the processor and, therefore, a breach by the lessee of its covenant “to manage and administer the leases as a reasonably prudent operator.”⁶⁵² After stating that Texas law does not recognize a “duty to manage and administer the lease as a reasonably prudent operator” separate and distinct from the implied covenant to market, the supreme court declined to certify Subclass 3 due to a lack of commonality because (a) the class contained both “market value at the well” and “amount realized” leases, and market value leases do not have the benefit of the implied covenant to market, and (b) the relative fairness of the NGL allocation to the affiliated gas processor had to be measured case by case.⁶⁵³

Similar results were reached in several of the other class action decisions.⁶⁵⁴ With the exception of the supreme court’s comments about the evidentiary showing of the Subclass 1 plaintiffs owners in *Bowden*, however, none of these cases actually addressed substantively the claims of the plaintiff/royalty owners.

⁶⁵¹ *Id.* at 702, n. 5.

⁶⁵² *Id.* at 708.

⁶⁵³ *Id.* at 708-709.

⁶⁵⁴ *E.g.*, *Stirman v. Exxon Corp.*, 280 F.3d 554, 563 (5th Cir. 2002); *Hunter v. Exxon Corp.*, 2005 WL 357682 (W.D. Tex. 2005); *Enron Oil & Gas Corp. v. Joffrion*, 116 S.W.3d 215 (Tex. App. – Tyler 2003, *no pet.*).

3. Recent Cases.

Two recent cases also merit discussion in this regard. In *Ramming v. Natural Gas Pipeline Co. of America*,⁶⁵⁵ a case involving lessor allegations of underpayment of royalties based on the lessee's alleged improper deduction of certain post-production costs, gas was sold at the wellhead by the current lessee's predecessor in interest pursuant to a gas contract with the midstream affiliate of the predecessor in interest.⁶⁵⁶ The oil and gas lease in controversy provided for royalty based on both "the net proceeds from the sale at the mouth of the cell" and the "market value at the well."⁶⁵⁷ The midstream affiliate of the lessee's predecessor in interest deducted gathering and transportation costs from the sales proceeds paid under the gas contract, and both the current lessee and its predecessor in interest paid royalty based on such net sale proceeds.⁶⁵⁸

The district court entered judgment in favor of the royalty owners, holding that the current lessee improperly deducted the gathering and transportation costs in calculating royalty and, citing *Hagen*, that the referenced gas contract was a sham transaction that did not provide a proper basis for calculating royalty.⁶⁵⁹

The United States Court of Appeals for the Fifth Circuit, however, reversed the district court's judgment, concluding that the lower court erred in finding that the post-production costs were the result of a sham

transaction. According to the court, there was no evidence of an *alter ego* relationship between the current lessee's predecessor in interest and such predecessor's midstream affiliate, stating that "the mere fact that a subsidiary is wholly owned by the parent and there is an identity of management does not justify" the finding of a sham transaction.⁶⁶⁰ Holding that the deduction of post-production costs was permissible under the relevant royalty clauses, the court also concluded that the royalty owners had introduced no evidence that the amount of such costs was unreasonable.⁶⁶¹

Most recently, in *Occidental Permian Ltd. v. The Helen Jones Foundation*,⁶⁶² a case involving the determination of royalty due on casinghead gas produced from a CO₂ flood unit and processed for the removal of NGLs and CO₂ in a lessee-owned processing plant,⁶⁶³ recall that the casinghead gas was sold at the wellhead pursuant to life-of-the-processing-plant POP contracts entered into many years before the current lessee acquired its interests in the underlying oil and gas leases and the plant. Under the POP contracts, the lessee received a price for 100% of the casinghead gas equal to 50% of the proceeds from the sale of residue gas and 33.3% of the proceeds from the sale of NGLs attributable to the casinghead gas.⁶⁶⁴

Among several other claims, the royalty owners argued that the current lessee breached the implied covenant to market by continuing to sell the casinghead gas under the old POP contracts.⁶⁶⁵ The royalty owners emphasized the self-dealing nature

⁶⁵⁵ 390 F.3d 366 (5th Cir. 2004).

⁶⁵⁶ *Id.* at 372.

⁶⁵⁷ *Id.*

⁶⁵⁸ *Id.* at 373.

⁶⁵⁹ *Id.*, citing *Texas Oil & Gas Corp. v. Hagen*, 683 S.W.2d 24 (Tex. Civ. App. – Texarkana 1984), *aff'd in part, and rev. in part*, 31 Tex. Sup. Ct. J. 140 (1987), *judgmt and op. of Tex. Sup. withdrawn, judgmt of Tex. Civ. App. set aside, motion of reh. and cause dismissed as moot*, 760 S.W.2d 960 (Tex. 1988).

⁶⁶⁰ 390 F.3d at 374.

⁶⁶¹ *Id.*

⁶⁶² 333 S.W.3d 392 (Text. App. – Amarillo 2011, *pet. denied*).

⁶⁶³ For a complete discussion of the facts and holdings in *Helen Jones*, see text accompanying notes 165 through 167 and 533 through 546, *supra*.

⁶⁶⁴ 333 S.W.3d at 396-397.

⁶⁶⁵ *Id.* at 403.

of the gas marketing transaction (with the current lessee selling the casinghead gas to itself as the owner of the processing plant) and argued that the lessee should have modified the terms of the POP contract to improve the percentage of the NGLs and residue gas payable to the lessee “because it, acting alone, had the power to do so.”⁶⁶⁶

The court of appeals rejected the royalty owners arguments, noting that while the implied covenant to market is intended to protect the lessors from the self-dealing of the lessee,⁶⁶⁷ a showing of self-dealing alone does not establish a breach of the implied covenant to market.⁶⁶⁸ The court found that (a) there was no evidence that the POP contracts were unreasonable when executed by the prior lease operator; (b) there was no evidence that the lessee would have had the ability to terminate or modify the POP Contracts if it were not also the plant owner; and (c) the royalty owners failed to prove what a reasonably prudent operator would have done differently under the same or similar circumstances.⁶⁶⁹

C. Lessons From the *Chesapeake* Cases.

From the preceding discussion, we have learned that although affiliate marketing transactions are “inherently suspect,”⁶⁷⁰ no Texas court has ever held such transactions to be inherently fraudulent. Indeed, neither the mere fact that the lessee’s marketing affiliate resells the gas for a price higher

than the price paid to the lessee,⁶⁷¹ nor the mere fact that a gas marketing company is a wholly owned subsidiary of a producer with shared management,⁶⁷² nor a simple showing of self-dealing⁶⁷³ is sufficient to establish a breach of the implied covenant to market.

Perhaps the most interesting recent cases that arise out of producer/marketing affiliate transactions come from the recent decisions involving Chesapeake Exploration, L.L.C., as to which the central issue, in each case, was the deductibility of post-production costs – *Potts v. Chesapeake Exploration, L.L.C.*,⁶⁷⁴ and *Chesapeake Energy, L.L.C. v. Hyder*.⁶⁷⁵ Both of these cases involve the same general gas marketing scenario. COI, the operating company affiliate of Chesapeake Exploration, L.L.C. (“Chesapeake”), as agent for Chesapeake, sells the gas produced from Chesapeake’s leases to CEMI, Chesapeake’s gas marketing affiliate, at the wellhead. CEMI then causes the gas to be gathered, transported, and ultimately delivered for resale to unaffiliated gas purchasers at one or more pipeline hubs (such as the Houston Ship Channel) located substantial distances from the leased premises. Rather than paying royalty based on the sale proceeds received by COI from CEMI at the wellhead, Chesapeake paid royalty based on a net-

⁶⁶⁶ *Id.* at 402-403.

⁶⁶⁷ *Id.* See *Phillips Petroleum Co. v. Yarbrough*, 405 S.W.3d 70, 78 (Tex. 2013) (“[I]ndeed, the purpose of an implied covenant claim is to protect a lessor from the lessee’s negligence or self-dealing that would result in unfairly low royalties.”)

⁶⁶⁸ *Id.*, citing *Yzaguirre v. KCS Resources, Inc.*, 53 S.W.3d 368, 373 (Tex. 2001).

⁶⁶⁹ 333 S.W.3d at 402-403.

⁶⁷⁰ *Parker v. TXO Production Corp.*, 716 S.W.2d 644, 646 (Tex. App. – Corpus Christi 1986, *no writ*).

⁶⁷¹ *Bowden v. Phillips Petroleum Co.*, 247 S.W.3d 690, 702 (Tex. 2008).

⁶⁷² *Ramming v. Natural Gas Pipeline Co. of America*, 390 F.2d 366, 374 (5th Cir. 2004).

⁶⁷³ *Occidental Permian Ltd. v. The Helen Jones Foundation*, 333 S.W.3d 392, 402-403 (Tex. App. – Amarillo 2011, *pet. denied*).

⁶⁷⁴ 760 F.3d 470 (5th Cir. 2014).

⁶⁷⁵ 2015 WL 3653446 (Tex. 2015). In the third “Chesapeake” case, *Warren v. Chesapeake Exploration, L.L.C.*, 759 F.3d 413 (5th Cir. 2014), the Fifth Circuit noted the presence of conflicting information about the marketing scenario in the pleadings, and although the court cited several statements indicating a marketing scenario similar to that in *Potts* and *Hyder*, the court concluded that a single gas sale took place downstream of the wellhead. *Id.* at 415-416.

back calculation of the market value at the well equal to the volume weighted and average sale price received by CEMI from its downstream resales of gas to unaffiliated gas purchasers (in each case, a “WASP”) less certain post-production costs.⁶⁷⁶

Of the three cases, the Fifth Circuit in *Potts* was the most mindful of Chesapeake’s affiliated gas marketing structure. The applicable royalty clause required the payment of royalty on gas production based on the “market value of the gas sold or used. . .” and also contained a no-post-production costs provision.⁶⁷⁷ As part of the court’s *Heritage Resources*-based analysis of the meaning of “at the well” and the ineffectiveness of the no-post-production costs provision,⁶⁷⁸ Judge Owen, writing for the court, stated:

Since it is undisputed that gas sales by Chesapeake have occurred at the wellhead, and since the lessors do not contend that the sales to unaffiliated purchasers were at less than market value, Chesapeake could arrive at market value at the wellhead by deducting [from the WASP] reasonable post-production costs to deliver the gas from the wellhead to the [point of sale] to unaffiliated purchasers.⁶⁷⁹

The *Potts* leases also provided that royalty on gas not sold in an arm’s-length transaction – i.e., an affiliate sale – was to be based, not on actual sale proceeds, but on “prevailing values at the time in the

area.”⁶⁸⁰ The court rejected the royalty owners’ argument that such provision prevented the point of sale from being the wellhead, stating that the provision “does not require the point of sale to be the point at which the gas is ultimately sold to a non-affiliated entity.”⁶⁸¹ Finally, the court rejected the royalty owners’ argument that treating the wellhead as the point of sale “frustrated the parties expectations and their reliance on the concurring opinion in *Heritage*.”⁶⁸² According to Judge Owen, “. . . Chesapeake has sold the gas at the wellhead. That is the point of sale at which market value must be calculated.”⁶⁸³

To this author, *Potts* is fascinating not only for what the case says, but also for what it does not say. There are no royalty owner claims based on the breach of the implied covenant to market, the existence of a sham sale transaction or a sham to perpetrate a fraud, an *alter ego* relationship between Chesapeake and its subsidiaries, or any of the other theories traditionally asserted in producer/marketing affiliate cases. As Judge Owens emphasized repeatedly, the case was decided exclusively based on the language of the *Potts* leases. Why was the case pleaded this way? We suggest that the critical factor in this regard was Chesapeake’s decision to use its WASP as the starting point for its net-back calculation of market value at the well. This approach effectively conceded that which the royalty owners had sought in every producer/marketing affiliate case from *Hagen* to *Ramming* – to have royalty calculated based on the marketing affiliate’s resale price. The only issue left to litigate, then, was the deductibility of post-production costs.

⁶⁷⁶ *Potts*, 760 F.3d at 471, 472; *Hyder*, 427 S.W.3d 472, 475 (Tex. App. – San Antonio 2014), *aff’d*, 2015 WL 3653446 at 3 and n. 7 (Tex. 2015).

⁶⁷⁷ *Potts*, 760 F.3d at 471-472.

⁶⁷⁸ *Id.* at 474-475.

⁶⁷⁹ *Id.* at 474.

⁶⁸⁰ *Id.* at 475-476.

⁶⁸¹ *Id.* at 476.

⁶⁸² *Id.*

⁶⁸³ *Id.*

This point is cast in even starker relief by *Hyder*.⁶⁸⁴ In that case, the marketing scenario was identical to that in *Potts*. The *Hyder* lease, however, provided for royalty on gas production based on “the price actually received by the Lessee for such gas . . .”⁶⁸⁵ The language of the royalty clause appears to require that the proceeds received by COI from CEMI in the wellhead sale of the gas be used as the basis for calculating royalty, but Chesapeake nonetheless paid royalty based on its WASP.⁶⁸⁶ Remarkably, neither the San Antonio Court of Appeals nor the Texas Supreme Court had any further comment about the significance (or lack thereof) of the producer/marketing affiliate transaction or the appropriateness of using Chesapeake’s WASP as the starting point for the royalty calculation under a “price actually received” lease, other than the supreme court’s notation, in a footnote, that “Chesapeake does not dispute that ‘the price actually received by the Lessee’ for purposes of the gas royalty is the gas sales price its affiliate, [CEMI], received, nor do the Hydres argue that the gas sales price was unfair”.⁶⁸⁷

Will the use of marketing affiliates’ WASPs, rather than the price paid by the marketing affiliate to producers, as the starting point for royalty calculation become the norm in producer/marketing affiliate transactions? That is difficult to predict. As can be seen from earlier discussions in this paper, WASPs have a somewhat checkered judicial history – disfavored as the basis for determining market value at the well in *Exxon Corporation v. Jefferson Land Co.*,⁶⁸⁸

⁶⁸⁴ *Chesapeake Exploration, L.L.C. v. Hyder*, 427 S.W.3d 472 (Tex. App. – San Antonio 2014), *aff’d*, 2015 WL 3653446 (Tex. 2015).

⁶⁸⁵ 2015 WL 3653446 at 2.

⁶⁸⁶ 427 S.W.3d at 475-476; 2015 WL 3653446 at 3.

⁶⁸⁷ 2015 WL 3653446 at 8, n. 17.

⁶⁸⁸ 573 S.W.2d 829 (Tex. Civ. App. – Beaumont 1978), *writ ref’d n.r.e. per curiam*, 681 S.W.2d 529 (Tex. 1980).

Vela, and *Middleton*,⁶⁸⁹; more favorably considered in *Hunter v. Exxon Corporation*⁶⁹⁰ and *Phillips Petroleum Co. v. Yarbrough*.⁶⁹¹ Further, unless a royalty owner is able to mount a successful challenge based on allegations of a breach of the implied covenant to market, or the existence of a sham sale, or a similar *alter ego*-based argument, the language of most “amount realized” or “proceeds” royalty clauses appears to require the use of the proceeds from the first gas sale by the producer to its marketing affiliate as the basis for calculating royalty, notwithstanding the courts’ lack of attention to the issue in *Hyder*. Of course, a case to determine that issue is much less likely to be filed as long as the marketing affiliate’s WASP is higher than the initial price paid by the marketing affiliate to the producer. Perhaps this is the most important lesson of the *Chesapeake* cases.

V. Conclusion

While *Vela*, *Middleton*, and, more recently, *Yzaguirre* once dominated the royalty litigation “conversation” between producers and royalty owners, *Heritage Resources’* holdings adopting the “net-back” method of calculating market value at the well and concerning post-production costs now largely drive the producer/royalty owner debate. Answers to some questions are

⁶⁸⁹ *Texas Oil & Gas Corp. v. Vela*, 429 S.W.2d 866, 873 (Tex. 1969) (the mathematical average of all prices prevailing in the field does not necessarily yield the market price at any particular point in time); *Exxon Corp. v. Middleton*, 613 S.W.2d 240, 249 (Tex. 1981).

⁶⁹⁰ 2005 WL 357682 at 4 (W.D. Tex. 2005) (“ . . . [A] field price was an average calculated monthly by defendant of index prices published monthly by industry publications . . . Each index price was an accurate reflection of actual third party sales made by producers other than defendant during that month. Each index is an as-delivered-at-the-marketplace price that does not deduct any allowance for post-production costs. The fact that this index pricing apparently reflects the average pricing for third-party sales suggests that Defendant may not be liable for any damages to the royalty interest owners.”).

⁶⁹¹ 405 S.W.3d 70, 74, 78-79 (Tex. 2013).

starting to emerge. For example, *Warren*, *Potts* and, in particular, *Hyder* appear to have provided to royalty owners relatively clear guidance about how to craft royalty clauses in future oil and gas leases that limit, or even eliminate, royalty owner exposure to post-production costs. Do not expect these developments to reduce the pace or volume of producer/royalty owner litigation, however. Gas royalty calculation is complex, and there is often significant money involved. Those two factors alone are reason enough to anticipate more litigation in this area.

It seems fair to anticipate that post-production cost litigation will continue, as royalty owners attempt to fit the increasingly customized royalty clauses in more recent oil and gas leases into one or more of the niches approved, or at least spoken of favorably, by the courts in the *Chesapeake* cases. This author would be very interested to see litigation involving a producer/marketing affiliate transaction that addresses directly the appropriateness of paying royalty based on the producer's WASP under an "amount realized" or "proceeds" royalty clause – assuming a royalty owner willing to file such a lawsuit could be found.⁶⁹² Certainly, the witches' brew of division order cases – from *Middleton* and *Cabot*, to *Gavenda*, to *Heritage Resources* – coupled with the ambiguities in the 1991 Texas division order legislation seem very likely – indeed, are overdue – to spawn a series of lawsuits. The questions whether index prices are an appropriate measure of market value,⁶⁹³ and

whether basis differentials constitute hidden post-production costs,⁶⁹⁴ are other questions that, in my view, are ripe for judicial consideration. Whatever the nature of the future disputes, however, it appears that, in most cases, *Heritage Resources* will, for better or worse, provide the primary analytical framework for the legal issues that will be raised.

⁶⁹² See text following note 691, *supra*.

⁶⁹³ In a decision by the Dallas Court of Appeals concerning an alleged breach of the implied covenant to market based on the alleged failure of the producer to obtain the best price reasonably possible, the Dallas Court of Appeals embraced the notion that prices payable for gas on the spot market are, indeed, probative of the best price reasonably obtainable by a reasonably prudent operator. *Hutchings v. Chevron U.S.A., Inc.*, 862 S.W.2d 752, 761-62 (Tex. App. – Dallas 1993, *writ denied*.) See also *Hunter v. Exxon Corp.*, 2005 WL 357682 at 4 (W.D. Tex. 2005), quoted in note 690, *supra*.

⁶⁹⁴ See text accompanying notes 476 through 482, *supra*.

