EXPLORING THE ORIGINS OF ROYALTY DISPUTES[1]

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The Oil and Gas Lease and the Use of Royalty

The oil and gas lease is an American invention designed to give the lessee an exclusive option to develop leased land.[2] In the event development is undertaken, and is successful, the lessor will be entitled to a "royalty."[3] However, the term "royalty" does not describe what the lessor is entitled to in the event of production. The term merely indicates the lessor will be compensated in some fashion because development has been successful. For example, if oil is produced, the lessor's "royalty" may be a fractional share of the oil that is produced and saved.[4] In early oil and gas leases, the lessor's

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[1] This article is adapted from David E. Pierce, "From Extraction to Enduse: The Legal Background," *Special Institute on Private Oil & Gas Royalties* (Rocky Mtn. Min. L. Fdn. 2003).

[2] John S. Lowe et al., Cases and Materials on Oil and Gas Law 126 (4th ed. 2002) ("The lessee seeks the *right* to develop the leased land for an agreed term without any *obligation* to develop . . . ."). For an interesting and authoritative discussion of the origin of the oil and gas lease see: Leslie Moses, "The Evolution and Development of the Oil and Gas Lease," 2 *Inst. on Oil & Gas L. & Tax'n* 1 (1951).

[3] As Professor Kuntz observed: "The purpose of the royalty clause of an oil and gas lease is to describe the benefits which are intended to inure to the lessor as the result of extraction of the described valuable substance by the lessee." 3 Eugene Kuntz, *A Treatise on the Law of Oil and Gas* 255 (1989).

[4] The lease might provide:

> The royalties to be paid by Lessee are as follows: On oil, *one-eighth of that produced and saved from said land*, the same to be delivered at the wells or to the credit of Lessor into the pipe line to which the wells may be connected. Lessee shall have the option to purchase any royalty oil in its possession, paying the market price therefor prevailing for the field where produced on the date of purchase.

compensation for gas was a stated sum per completed gas well.[5] The precise terms of the lease,[6] and the facts surrounding the production and sale of oil and gas,[7] will define the "royalty" that is due.

In addition to the oil and gas lease, there are other oil and gas relationships that entitle a party to a "royalty." For example, the right to receive a royalty can be conveyed directly from the owner of the minerals.[8] This is called a "nonparticipating royalty interest" and could look like the following conveyance:

ROYALTY DEED

A conveys to **B** the right to receive one-half of the royalty provided for in any oil and gas lease covering the following land:

Section 3, Township 11 South,
Range 15 East of the 6th Principal
Meridian in Shawnee County,
Kansas.

Eugene O. Kuntz et al., *Forms Manual to Accompany Cases and Materials on Oil and Gas Law 12*, at ¶ 3 (3d ed. 1998) (emphasis added) [hereinafter *Forms Manual*]

[5]Professor Kuntz devotes an entire section to the "fixed gas royalty" in his treatise. 3 Kuntz, *supra* note 3, at § 40.2.

[6]The terms of other documents may also impact the royalty that is due. For example, pooling agreements and division orders may impact the terms of the oil and gas lease. *See* p. 20 (pooling) and p. 30 (division orders), *infra*.

[7]For example, determining the royalty obligation will require an examination of the oil and gas lease and consideration of facts external to the lease. Relevant external facts include the volume extracted, the nature of the substance extracted (oil, gas, condensate?), and the way it is disposed of by the parties (oil taken by the lessor or still in the "possession" of the lessee? Gas sold at the well or "used" by the lessee or sold away from the well?).

[8]*See* 1 KUNTZ, *supra* note 3, at § 15.4.

An immediate issue is to what extent will the terms of the underlying oil and gas lease impact the calculation of **B**'s royalty interest? The issue is even more difficult in the following type of nonparticipating royalty:

ROYALTY DEED

A conveys to **B** 1/16th of all the oil, gas, and other minerals produced from the following land:

Section 3, Township 11 South, Range 15 East of the 6th Principal Meridian in Shawnee County, Kansas.

Depending upon the timing of the conveyance, the grantee (**B**) may, or may not, have a relationship with the oil and gas lessee. The calculation of what **B** is due in the event of production becomes difficult because the language contained in the royalty deed is often no more revealing than in the above examples.[9]

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[9]In Kansas it would appear that each of these nonparticipating royalty conveyances is void as a violation of the Rule Against Perpetuities. The Kansas Supreme Court has held that the "vesting event" for a nonparticipating royalty is when there is actual production from the land at issue. *Lathrop v. Eyestone*, 227 P.2d 136 (Kan. 1951); *Cosgrove v. Young*, 642 P.2d 75 (Kan. 1982). Therefore, the inquiry becomes: as of the date the conveyance was made, is it certain that production will be obtained from the land within a life or lives in being plus 21 years? If the answer is "no," the interest is void. *See* 1 David E. Pierce, *Kansas Oil and Gas Handbook* §§ 4.13 & 4.15 (1986). The flaw in the court's analysis is that by focusing on whether there will be production from the land, it is equating the "value" of the interest with its "vesting." In this respect, the nonparticipating royalty interest is no different from a mineral interest, which Kansas deems to vest upon conveyance. *Lathrop*, 227 P.2d at 141. It is even possible to create a non-participating *mineral* interest in Kansas, devoid of all mineral attributes other than the right to receive royalty, and it would be deemed to vest upon its conveyance. *Drach v. Ely*, 703 P.2d 746 (Kan. 1985); 1 Pierce at § 4.16. Although it appeared the Kansas Legislature mitigated this problem in 1996 with passage of the Uniform Statutory Rule Against Perpetuities, Kan. Stat. Ann. §§ 59-3401 to 59-3408 (1994) (USRAP), I believe the legislation adopting the USRAP in Kansas is void as

Royalty calculation issues also arise when the oil and gas lessee conveys the right to receive a noncost-bearing ("cost-free") share of production payable out of the working interest owner's share of production: an "overriding" royalty.[10] An overriding royalty may provide:

ASSIGNMENT

A assigns to **B** the right to receive 1/16th of all the oil, gas, and other minerals produced under the Fred Farmer to **A** Oil and Gas Lease dated 1 May 2002, covering the following land:

Section 3, Township 11 South, Range 15 East of the 6th Principal Meridian in Shawnee County, Kansas.

As with the nonparticipating royalty interest, a major issue is how the overriding royalty will be calculated and whether **B**'s royalty rights will be governed by the same royalty calculation jurisprudence that defines the rights of the lessor/landowner and lessee/producer.

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violating the Kansas Constitution prohibiting multiple subjects in a single bill. Kan. Const. art 2, § 16 ("No bill shall contain more than one subject, except appropriation bills and bills for revision or codification of statutes."). Fortunately, courts in other jurisdictions have held that nonparticipating royalty interests vest immediately upon conveyance, thereby avoiding the perpetuities issue. Lowe et al., *supra* note 2, at 340-41.

[10]Professors Kramer and Martin trace the evolution of the term "overriding royalty" in Patrick H. Martin and Bruce M. Kramer, *Williams & Meyers Manual of Oil and Gas Terms 748-53* (10th ed. 1997) [hereinafter *Manual of Oil and Gas Terms*]. The context of the term today is as follows: "Thus as of 1960 the primary usage of the term 'overriding royalty' in the United States was in connection with interests created by an oil and gas lessee by grant or by reservation, and this continues to be true at the present time." *Id.* at 749.

The Inherent Conflict Between Royalty Owner and Lessee

Maximizing Royalty

Once the oil and gas lease is executed, there are only two ways the lessor can increase their revenue under the lease: (1) an increase in the *volume* of oil and gas produced; and (2) an increase in the *value* of that which is produced.[11] As I have noted previously: "The situs of the lessor's volume- and value-enhancing efforts is often a courthouse."[12] The lessor has traditionally addressed volume issues relying upon an implied covenant to protect against drainage and to further explore and develop the leased lands.[13] Value issues typically focus on the meaning of the royalty clause which, in turn, trigger the royalty value theorem.

The Royalty Value Theorem

I first posited the royalty value theorem at the Rocky Mountain Mineral Law Foundation's Federal and Indian Oil & Gas Royalty Valuation & Management III special institute where I stated:

> When compensation under a contract is based upon a set percentage of the value of something, there will be a tendency by each party to either minimize or maximize the value.[14]

This is also the foundation for why there will never be peace—under the oil and

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[11]David E. Pierce, "The Missing Link in Royalty Analysis: An Essay on Resolving Value-Based Royalty Disputes," 5 *Texas Wesleyan L. Rev.* 185 (1999) [hereinafter Missing Link in Royalty Analysis].

[12]*Id.*

[13]The volume issues present their own set of lessor/lessee conflicts under the oil and gas lease. *See* David E. Pierce, "Rethinking the Oil and Gas Lease," 22 *Tulsa L. J.* 445, 459-60 (1987); David E. Pierce, "Coordinated Reservoir Development–An Alternative to the Rule of Capture for the Ownership and Development of Oil and Gas: Part I," 4 *J. Energy L. & Pol'y* 1, 33-49 (1983).

[14]David E. Pierce, What's Behind the Valuation Controversy Anyway?" *Federal & Indian Oil & Gas Royalty Valuation & Management III*, 1-1 (Rocky Mtn. Min. L. Fdn. 2000).

gas lease.[15] To the extent there is room for interpretation, argument, or a new theory, there will be an incentive to challenge the other party's view of what is required under the lease. If an argument can be made for a fraction of "X+" instead of the fraction of "X" that is being paid, litigation will ensue when the "+" is worth the effort. The "+" is often pursued when the potential value of the argument can be magnified through the class action procedural device.

However, the "+" at issue in the *value*-driven royalty context is fundamentally different from the "+" at issue in *volume*-driven cases. For example, when the issue concerns the lessee's failure to further develop, the test is whether a "prudent operator" would conduct further development. The prudent operator would only conduct further development if the costs of development will likely be recovered, plus a reasonable profit, from the "new" production. The "+" is the new profit that will be obtained from new production. In the value context, there is no new profit or value, but merely a reallocation of existing value and profit based upon a new entitlement theory. Courts are merely deciding how the finite pie will be re-cut. If the lessor is held to be entitled to downstream values, and the lessee has been paying royalty based on upstream "at the well" values, the lessor's slice will get bigger and the lessee's slice will get correspondingly smaller. The analysis will be similar when the issue is whether royalty must be paid on downstream investments to obtain downstream values.[16]

The Royalty Value Theorem in Practice: The Basic Issues

The Linear Enhancement of Production Value

As a general proposition, as oil or gas moves downstream from the wellhead it increases in value. This increase in value is comprised of two components: (1) investments made in the production either by the lessee providing a facility or service or purchasing the service from others;[17] and (2) the increased value of the production in a particular form at a particular

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[15]"Why There will Never be Peace–Under the Oil and Gas Lease" is a heading I use in a discussion of the royalty value theorem in David E. Pierce, "The Royalty Value Theorem and the Legal Calculus of Post-Extraction Costs," 23 *Energy & Min. L. Inst.* 16-1 (2002) [hereinafter Legal Calculus of Post-Extraction Costs].

[16]This is more commonly expressed as a "deduction of costs" issue.

[17]This would include such things as gathering, compression, treating, processing, refining, aggregating, packaging, and marketing.

location. For example, the lessee may spend 50¢/Mcf[18] in gathering and compression costs to transport gas from the wellhead to an interstate pipeline. If we assume the gas has a wellhead value of $1.00/Mcf, and a value at the point where the gathering system enters the interstate pipeline of $1.55/Mcf, the total enhanced value is comprised of the 50¢ in additional investment plus 5¢ in additional value. As the gas moves further downstream from the wellhead it is typically subject to additional value-increasing investment until it is sold to the purchaser that consumes the gas.

When the phenomenon of linear enhancement of production value is combined with the royalty value theorem, the lessor/lessee battle lines become clear: lessees will seek to value production for royalty purposes as close to the point of extraction as possible while lessors will seek to value production as far downstream from the point of extraction as possible. If a downstream value is used to calculate royalty, lessees will seek to deduct the investment value (the 50¢/Mcf in the prior example) of the gas before applying the royalty fraction.[19] Lessors will seek to have their royalty calculated on the total downstream value (the $1.55/Mcf in the prior example) without deduction of any investment value.

Defining the Scope of the Oil and Gas Lease Relationship

One of the foundational issues in addressing royalty obligations is defining the scope of the oil and gas lease relationship. The basic question is: when does the oil and gas lease cease to govern oil or gas that has been extracted from the ground? Since the oil and gas lease is the source of the lessor's royalty rights, it will be to their benefit to keep extracted oil and gas subject to

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[18]The volumetric unit of measure for natural gas is "thousand cubic feet" or "Mcf;" the heating value unit of measure is "million British thermal units" or "MMBtus." One Mcf of gas equals one MMBtu when the Btu content of the gas is 1,000 Btu per cubic foot. Thomas G. Johnson, *Handbook on Gas Contracts* 36 (1982).

[19]This approach would give the lessor a royalty on $1.05/Mcf ($1.55 - 50¢). If the lease provided for a royalty using the market value at the place where the gas was extracted (e.g., "at the well") the lessor would receive a royalty on $1.00/Mcf. However, the outcome varies from state-to-state depending upon the approach it takes in defining "market value" and the effect given to phrases such as "at the well" or "at the mouth of the well." Compare *Yzaguirre v. KCS Resources, Inc.*, 53 S.W.3d 368 (Tex. 2001) (relying upon "market value" language to define the parties' rights) with *Rogers v. Westerman Farm Co.*, 29 P.3d 887 (Colo. 2001) (disregarding "at the well" and "at the mouth of the well" language in the leases at issue).

the lease terms as long as possible. This provides the lessor with a contract-based argument for downstream values by asserting the oil or gas is still subject to the lease until it reaches some downstream location.[20] The lessee will argue that when the oil and gas is extracted it will often trigger a royalty obligation that begins, and ends, at the leased premises.[21]

I have previously stated the basic issue as follows:

> At what point in the oil and gas development and production process are the lessor and lessee no longer contractually obligated to one another? When has the relationship run its course?
>
> Although the parties' rights and obligations continue under the oil and gas lease, courts must define the limits of the document's sphere of influence. Only then can courts make accurate decisions concerning value-based royalty disputes. When a challenged activity falls outside the scope of the lease relationship, the analysis is at an end. There will be no contractual basis for asserting rights or imposing obligations on the parties. There can be no rights or duties if there is no contractual relationship. Similarly, there can be no implied obligations which of necessity must emanate from some sort of contractual relationship.[22]

Therefore, once a barrel of oil, or Mcf of gas, is extracted from the ground, at what point does it cease to be impacted by the parties' oil and gas lease? These issues will be initially addressed by looking to the express terms of the oil and gas lease.[23] This is where the lessee will argue the inquiry should begin, and

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[20]Professor Weaver provides examples of how these arguments can be structured in: Jacqueline Lang Weaver, "When Express Clauses Bar Implied Covenants, Especially in Natural Gas Marketing Scenarios," 37 *Nat. Resources J.* 491, 528-42 (1997). The most aggressive argument for giving the oil and gas lease an expansive downstream presence has been made by a prominent attorney active in class action royalty litigation on behalf of lessors: John Burritt McArthur, "The Mutual Benefit Implied Covenant for Oil and Gas Royalty Owners," 41 *Nat. Resources J.* 799 (2001).

[21]Missing Link in Royalty Analysis, *supra* note 11, at 189-90.

[22]*Id.* at 186.

[23]Lessees will focus on:

> For example, the granting clause grants the lessee rights to explore, develop, and produce from, *the leased land.* The duration of the lease will continue only so long as there is production from *the*

end. The lessor will argue the express terms need to be interpreted[24] and, in most cases, also need to be supplemented by an implied covenant to market.[25]

Impact of Regulatory Change

Most of the major royalty calculation disputes can be attributed to "change."[26] One of the major sources of change in the oil and gas industry is government regulation.[27] For the gas industry,[28] the major regulation consisted

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> *leased land.* Activities to extend the lease beyond the stated term must take place on *the leased land.* Royalty is generated only from production that is obtained from *the leased land.* The lessee will argue that the scope of the relationship is defined by the leased land so that whatever business activities the lessee engages in away from the leased land are independent from its lease obligations.

David E. Pierce, "The Renaissance of Law in the Law of Oil and Gas: The Contract Dimension," to be published in Volume 43, Issue 1of the *Washburn Law Journal* [hereinafter Renaissance].

[24]Thereby seeking to invoke the "construe against the lessee" canon of construction. *See* Bruce M. Kramer, "The Sisyphean Task of Interpreting Mineral Deeds and Leases: An Encyclopedia of Canons of Construction," 24 *Texas Tech L. Rev.* 1, 105-08 (1993) [hereinafter Canons of Construction].

[25]*See generally* McArthur, *supra* note 20, at 834-37.

[26]For example, the definition of "market value" when gas is subject to government regulation that prevents the lessee from selling their gas at its current market value. *See generally* David E. Pierce, "Royalty Calculation in a Restructured Gas Market," 13 *Eastern Min. L. Inst.* 18-1, 18-9 to 18-19 (1992) [hereinafter Restructured Gas Market]. For an excellent discussion of the development and evolution of the natural gas industry, including its regulatory component, see The Energy Law Group, "Energy Law and Policy for the 21st Century 8-1 to 8-31" (Rocky Mtn. Min. L. Fdn. 2000) (Chapter 8, *Natural Gas*, by Suedeen G. Kelly).

[27]The Appendix contains a summary of the major regulatory events impacting the natural gas industry from 1911 to the present.

[28]The oil industry has not been as extensively regulated, nor has the regulation tended to segment the oil industry the way the gas industry became segmented under the Natural Gas Act of 1938. Unlike natural gas pipelines, interstate oil pipelines have been regulated as common carriers. Pub. L. No. 337, § 1, 34 Stat. 584 (1906) (the "Hepburn Amendment" to the Interstate Commerce Act). Since 1906 oil producers, and oil purchasers, have had access to oil pipeline transportation facilities. Open access

of federal control over all interstate pipeline services from 1938[29] through 1992[30] and federal regulation of producer prices and sales from 1954[31] through 1992.[32] The combined effect of these five decades of regulation was to segment the industry so that most gas sales took place at or near the place where the gas was extracted. The producer would typically transfer title to the gas, in a sales transaction in the field where produced, to the interstate pipeline company.[33] The pipeline company would then move the gas downstream to the point were it was resold to an end-user or a local distribution company. Rarely would the producer engage in extensive marketing efforts downstream of the leased premises because transportation facilities were not available to the producer to move gas to an end-user.

This situation began to change in 1985 as the Federal Energy Regulatory Commission ("FERC") commenced the process of requiring pipeline companies to provide "open access" to their systems.[34] For the first time gas

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to gas pipeline transportation facilities did not become available until the 1980s.

[29]Beginning with the Natural Gas Act of 1938, 15 U.S.C. §§ 717-717z (1994).

[30]The major concluding event would be the adoption of FERC 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*, III F.E.R.C. Stats. & Regs. [Regs. Preambles] ¶ 30,939 (1992).

[31]*Phillips Petroleum Co. v. Wisconsin*, 347 U.S. 672 (1954).

[32]Under the Natural Gas Wellhead Decontrol Act of 1989, Pub. L. No. 101-60, 103 Stat. 157 (1989), all federal price and service regulations governing natural gas sales were eliminated as of January 1, 1993.

[33]Depending upon the regulatory classification of the gas, the lessee in some instances could sell to an intrastate pipeline company, another re-seller, or an end-user.

[34]The process began with FERC Order 436 and the subsequent Order 500 refinements of Order 436. *Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol*, F.E.R.C. Stats. & Regs., Regs. Preambles 1982-85 ¶ 30,665 (1985), *vacated and remanded*; *Associated Gas Distributors v. Federal Energy Regulatory Comm'n*, 824 F.2d 981 (D.C. Cir. 1987), *cert. denied*; 485 U.S. 1006 (1988), readopted on an interim basis, Order No. 500, F.E.R.C. Stats. & Regs., Regs. Preambles, 1986-90 ¶ 30,761 (1987), *remanded*; *American Gas Association v. Federal Energy Regulatory Comm'n*, 888 F.2d 136 (D.C. Cir. 1989), *readopted*; Order No. 500-H, F.E.R.C. Stats. & Regs., Regs. Preambles 1986-90 ¶ 30,867 (1989), *reh'g granted in part and denied in part.* Order No. 500-I, F.E.R.C. Stats. & Regs., Regs. Preambles 1986-90 ¶ 30,880 (1990),

producers could seek customers for their gas at an unlimited number of locations downstream from the wellhead.[35] As lessees adjusted their business practices and corporate structures to respond to the new regulatory realties, the basic approach to marketing gas changed. The changes often meant new problems for lessees but also provided gas owners with new marketing options and opportunities—and new risks and rewards.

Impact of Changing Marketing Patterns

Many of the royalty issues currently before the courts relate to the rights of lessors and lessees under a new regulatory regime that has required, or allowed, new approaches to marketing gas. Under the traditional marketing scenario, lessees sold their gas under gas sales contracts having the following attributes:

1.) Dedication of the gas producing property to a particular gas purchaser,

2.) Long-term obligations lasting up to twenty years and in some cases for as long as the lease produced gas,

3.) Pricing provisions that, over time, often departed from the current value of the gas when produced,

4.) Delivery and transfer of title to the gas from the lessee to the purchaser at or near the place where it is produced, and

5.) Delivery obligations defined by the volumes the lease is able to produce.[36]

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aff'd in part and remanded in part; American Gas Assoc. v. Federal Energy Regulatory Comm'n, 912 F.2d 1496 (D.C. Cir. 1990), *cert. denied,* 498 U.S. 1084 (1991).

[35]The Appendix to this paper lists, in chronological order from 1984 to 1994, the process by which the FERC undertook to open access to the pipeline system and to eliminate historical regulatory restraints on gas supply and demand.

[36]*See Restructured Gas Market, supra* note 26, at 18-5 to 18-6.

Contrast the foregoing "traditional" marketing scenario with the "new" marketing scenario added by the regulatory changes taking place during the 1984/94 decade:

1.) Gas producing property is rarely "dedicated" or "committed" to a particular gas purchaser,

2.) Long-term obligations are rare; significant volumes are sold under contracts that do not exceed 30 days to numerous buyers other than the transporting pipeline,

3.) Pricing generally reflects the current value of the gas when produced,

4.) Delivery and transfer of title to the gas from the lessee to the purchaser may take place at a point distant from the place where it is produce, and

5.) Delivery obligations will be defined by a specified volume and not the production capability of a lease, or group of leases.[37]

Today we have a varied mix of traditional and new marketing patterns lessees use to dispose of their gas. Sometimes the lessee will pursue downstream marketing within its own organization; often a separate corporate entity will be created to pursue downstream activities.[38] Other lessees will continue to sell to purchasers at or near the well. These wellhead purchasers may own gathering systems, processing plants, or other leases in the area; they may own nothing other than gas contracts giving them the right to buy gas which they will aggregate, package, and re-sell to others.

The opportunity for downstream enterprising by the lessee, affiliates of the lessee, and other entrepreneurs highlights the linear nature of gas value: increasing as it moves away from the point of extraction.[39] Substituting these new entrepreneurs for the old pipeline purchaser creates new opportunities for

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[37]*Id.* at 18-7.

[38]Judith M. Matlock addresses this issue in her paper on: "Special Royalty Issues: Royalty Calculation When the Producer/Lessee is Dealing with an Affiliated Entity," *Special Institute on Private Oil & Gas Royalties* (Rocky Mtn. Min. L. Fdn., September 8-9, 2003).

[39]See p. 6, *supra.* ("The Linear Enhancement of Production Value").

the lessor under the royalty value theorem. These opportunities are being pursued vigorously which explains, in large part, the origins of today's royalty dispute.

Determining the Base Royalty

The first inquiry regarding royalty calculation is to determine the "substance" at issue. Is the substance "oil," "gas," or something in-between, such as "condensate," "distillate," or "natural gasoline?" The terms "condensate," "distillate," and "natural gasoline" describe the same basic type of substance and for this discussion the term "condensate" will be used.[40] The term "casinghead gas" refers to "[g]as produced with oil in oil wells . . . ."[41] The substances must be properly identified to determine the applicable royalty clause provisions. Although most oil and gas leases clearly distinguish between "oil" and "gas," many do not address gas that emerges from the well and then condenses into a liquid. Many leases are silent, some expressly address condensate under the *oil* royalty clause,[42] others expressly address it under the

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[40]The essence of each definition is production emerging from the wellbore in a gaseous phase and then condensing into a liquid phase at or near the leased premises. Among the common definitions for these terms are the following: "Condensate . . . is the liquid hydrocarbons recovered at the surface that result from condensation due to reduced pressure or temperature of petroleum hydrocarbons existing initially in a gaseous phase in the reservoir." *Manual of Oil & Gas Terms, supra* note 10,at 195. Distillate are "[l]iquid hydrocarbons, usually colorless and of high API gravity (above 60 degrees), recovered from wet gas by a separator that condenses the liquid out of the gas." *Id.* at 285. Natural gasoline is "[a] liquid similar to motor fuel recovered as Drip Gasoline . . . or produced in natural gasoline plants . . . ." *Id.* at 653. "Drip gasoline" is defined as "Natural gasoline . . . recovered at the surface as the result of separation (or dripping out) of certain of the liquid hydrocarbons which were dissolved in gas in the formation under high pressure but which come out of solution on the reduction of pressure at the surface." *Id.* at 312.

[41]*Id.* at 140.

[42]*E.g.*, "To deliver to the credit of lessor free of cost, in the pipeline to which it may connect its wells, the one-eighth (1/8) part of all oil (*including but not limited to condensate and distillate*) produced and saved from the leased premises." 7 KUNTZ, *supra* note 3, § 136.19, at 84 (emphasis added). Sometimes the language is not as explicit but merely refers to a royalty on "oil and other *liquid hydrocarbons* produced and saved *from the leased premises* . . . ." *Id.* at § 136.2, at 3, ¶ 3 (emphasis added). The location for determining the "liquid" phase can vary as well. Instead of evaluating the phase at the "leased premises" as in the foregoing example, another form focuses

gas royalty clause.[43] Frequently the royalty clause will have a provision dealing with gas and a separate provision addressing casinghead gas.[44] The matter may be addressed by a division order between the parties;[45] or by a pooling agreement.[46] Once all substances are properly categorized, the specific provisions of the respective "oil" and "gas" royalty provisions can be applied.

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on the phase when the material is produced: "On oil, and other hydrocarbons which are produced *at the well in liquid form* by ordinary production methods . . . ." *Id.* at § 136.9, at 38, ¶ 3.(a) (emphasis added).

[43]*E.g.*, "The royalties to be paid by Lessee are as follows: . . . . On gas, including casinghead gas, *condensate* and other gaseous substances, produced from said land . . . ." *Forms Manual*, *supra* note 4, at 12, ¶ 3 (emphasis added).

[44]*E.g.*, "Lessee shall pay to Lessor for *gas produced from any oil well* . . . . The Lessee shall pay Lessor as royalty one-eighth of the proceeds from the sale of gas as such at the mouth of the well *where gas only is found.*" 7 Kuntz, *supra* note 3, § 136.6, at 27, ¶ 4 (emphasis added).

[45]*E.g.*, "You may either purchase the crude oil *or other liquid hydrocarbons recovered on the Property* . . . . You may either purchase the gas (*including casinghead gas*) recovered on the Property . . . ." *Forms Manual*, *supra* note 4, at 54-55 (emphasis added). The Texas statutory form division order for oil states: "The undersigned . . . certifies it is the legal owner . . . of all oil *and related liquid hydrocarbons produced from the property* . . . ." Tex. Nat. Res. Code Ann. § 91.402(d) (Vernon 2001) (emphasis added).

[46]*E.g.*, "The term 'gas' as used herein means in *its natural state as produced from the well, including its content of gasoline and of all liquefiable hydrocarbons, and gas distillate or condensate*, but does not include casinghead gas and/or gas produced from oil wells. The term 'oil' means petroleum, including casinghead gas and/or any gasoline or other liquefiable hydrocarbons contained in the gas as produced from the same sand or formation as the oil." This is one of the frequently encountered forms of pooling agreement (typically titled "Consolidation Agreement" or "Unitization Agreement") used in the Kansas Hugoton Field where development has been on 640-acre drilling units.

Royalty on Oil

Most oil and gas leases begin by providing the lessor with an actual share of the produced and saved oil as the lessor's royalty on oil.[47] Consider the following clause:[48]

> 3. The royalties to be paid by Lessee are as follows: On oil, one-eighth of that produced and saved from said land, the same to be delivered at the wells or to the credit of Lessor into the pipe line to which the wells may be connected. . . .

The most striking aspect of this clause is the lessor becomes the owner of one-eighth of the oil as it is "produced and saved." This creates special problems for both lessor and lessee because the lessor typically does not do anything with its oil and long-term storage on the lease is rarely an option. The lessor is therefore the owner of personal property, the oil, which is classified as "goods" under Article 2 of the Uniform Commercial Code.[49] Often the lessor

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[47]However, as with any lease provision, nothing is uniform. For example, one form of lease provides:

> Lessee shall pay Lessors as royalty on oil the value of the agreed share of all oil produced and removed from the leased land, after making the customary adjustments for temperature, water and b.s. at the posted available market price at the well for oil of like gravity on the day the oil is so removed, or at Lessors' option, in lieu of such payment Lessee shall deliver the agreed share of oil, free of cost, into Lessors' tanks on the leased land or into a pipe line thereon designated by Lessors.

7 Kuntz, *supra* note 3, § 136.3 at 10, ¶ 8.

[48]*Forms Manual*, *supra* note 3, at 12.

[49]U.C.C. § 2-107(1) (1977) ("A contract for the sale of minerals or the like (including oil and gas) . . . is a contract for sale of goods within this Article if they are to be severed by the seller . . . ."). David E. Pierce, "Resolving Division Order Disputes: A Conceptual Approach," 35 Rocky Mtn. Min. L. Inst. 16-1, 16-46 to 16-49 (1989) [hereinafter Division Order Disputes].

will sell its oil at the lease with the sale being documented by a division order.[50] Frequently the division order will evidence a transfer of the lessor's oil to the lessee and establish the terms of the transfer. Consider the following:[51]

> TERMS OF SALE: The undersigned will be paid in accordance with the division of interests set out above. The payor shall pay all parties at the price agreed to by the operator for oil to be sold pursuant to this division order. Purchaser shall compute quantity and make corrections for gravity and temperature and make deductions for impurities.

In many oil royalty clauses the parties expressly address what can happen when the lessor fails to do something with its share of the oil. For example:[52]

> 3. The royalties to be paid by Lessee are as follows: On oil, one-eighth of that produced and saved from said land, the same to be delivered at the wells or to the credit of Lessor into the pipe line to which the wells may be connected. *Lessee shall have the option to purchase any royalty oil in its possession, paying the market price therefor prevailing for the field where produced on the date of purchase. . . .*

There can be considerable variation in lease language addressing what the lessee can, or must, do when the lessor fails to dispose of its share of oil.[53]

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[50]*Division Order Disputes, supra* note 49, at 16-46 to 16-47.

[51]This is from the Texas statutory form of oil division order. Tex. Nat. Res. Code Ann. § 91.402(d) (Vernon 2001).

[52] *Forms Manual, supra* note 4, at 12 (emphasis added).

[53]For example:

> 5. ROYALTY PAYMENT. The royalties to be paid to the Lessor are: (a) on oil, ⅛th of that produced and saved from said land, the same to be delivered at the wells or to the Lessor's credit into the pipelines to which the wells may be connected. Lessee shall have the continuing right to purchase such production at the wellhead market price then prevailing in the same field (or if there

Many of the disputes over oil royalty relate to determining the "market price" of the oil or interpreting other valuation terms, such as "posted available market price"[54] or "posted price."[55]

Royalty on Gas

In contrast to royalty on oil, the gas royalty is typically a share of a stated sum of money measured either by what the lessee sold the gas for ("proceeds" or "amount realized") or the value ("market value" or "market price") of the gas. Consider the following clause:[56]

> 3. The royalties to be paid by Lessee are as follows: On oil . . . . On gas, including casinghead gas, condensate and other gaseous substances, produced from said land and *sold or used off the premises or for the extraction of gasoline or other products therefrom, the market value* at the well of one-eighth of the gas so sold or used, provided that on *gas sold at the wells the royalty shall be one-eighth of the amount realized from such sale.*

This particular lease form combines the two valuation approaches ("market value" and "amount realized") depending upon whether the gas is "sold at the wells" or "sold or used off the premises or for the extraction of gasoline or other products . . . ." Frequently a lease will be encountered that provides

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> is no such price then prevailing in the same field, then the nearest field in which there is such a prevailing price) for production of similar grade and gravity. Lessee may sell any royalty oil in its possession and pay Lessor the price received by Lessee for such oil computed at the well.

7 Kuntz, *supra* note 3, § 136.14, at 58.

[54]7 Kuntz, *supra* note 3, § 136.3, at 10, ¶ 8.

[55] *Forms Manual, supra* note 3, at 54 ("If you purchase the oil, payments to Owner shall be based on your applicable posted price or, if there is no such posting, it shall be based on the prevailing wellhead market price paid for oil of the same quality on the same date in the same (or nearest) field.") (division order form). *See generally* James C. T. Hardwick, "Special Royalty Issues: Royalties on Oil," *Special Institute on Private Oil & Gas Royalties* (Rocky Mtn. Min. L. Fdn., September 8-9, 2003).

[56] *Forms Manual, supra* note 4, at 12 (emphasis added).

exclusively for an "amount realized"[57] calculation or exclusively for a "market value"[58] calculation.

Perhaps the most important aspect of these two valuation approaches is that in neither case will the lessor have any ownership interest in extracted gas. Instead all the gas will be the personal property of the lessee which the lessee can dispose of without the consent of the lessor. The lessor's royalty rights in the gas are contract rights the lessee must discharge in accordance with the terms of the oil and gas lease. Therefore the major valuation disputes typically revolve around determining the meaning of terms such as "amount realized," "market value," and the various permutations of the proceeds from a sale or the value of the gas sold or used.[59]

Post-Extraction Investments: Activities Beyond the Wellhead

One of the most contentious issues between lessors and lessees concerns "where" the base royalty valuation should be made. This is the "location" problem: where should the market price, posted price, amount realized, or market value be determined? Often the oil and gas lease will specify the location as being "at the well;"[60] sometimes the lease may specify a downstream location.[61] Depending upon how this first location issue is

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[57]*E.g.*, 7 Kuntz, *supra* note 3, § 136.16, at 69, ¶ 3 ("On gas, including casinghead gas or other gaseous substances, produced from said land and sold or used off the premises or for the extraction of gasoline or other products therefrom, ⅛th of the amount realized from said sale at the well, or which would be realized from such sale by the Lessee when computed at the well provided that on gas sold at the well the royalty shall be ⅛th of the amount realized from said sale.").

[58]*E.g.*, 7 Kuntz, *supra* note 3, § 136.5, at 24, ¶ 2nd ("To pay the lessor one-eighth, at the market price at the well for the gas so used, for the gas from each well where gas only is found, while the same is being used off the premises . . . .").

[59]*See generally* John S. Lowe, "Defining the Royalty Obligation," 49 *SMU L. Rev.* 223 (1996) (discussing royalty on take-or-pay benefits).

[60]*Forms Manual*, *supra* note 4, at 12 ("the same to be delivered at the wells" (oil) or "market value at the well" or "sold at the wells" (gas)).

[61]*E.g.*, 7 Kuntz, *supra* note 3, § 136.5, at 38, ¶ 3.(b) ("In case lessee shall itself use gas in the manufacture of gasoline or other petroleum products therefrom, ⅛ of the sale price *at the plant* of the gasoline or other petroleum products manufactured or extracted therefrom and which are saved and marketed . . . and ⅛ of the market value of *residue*

addressed, there may, or may not,[62] be a need to address the second issue: if a royalty calculation is made downstream from the wellhead, can any of the costs associated with moving the gas downstream be deducted from the downstream value before the royalty fraction is applied? Leases that provide for a royalty value downstream from the wellhead often address how costs incurred to obtain the downstream value should be addressed. For example, a version of the Louisiana "Bath" oil and gas lease form states:

> In case lessee shall itself use gas in the manufacture of gasoline or other petroleum products therefrom, ⅛ of the sale price *at the plant* of the gasoline or other petroleum products manufactured or extracted therefrom and which are saved and marketed, *after deducting a fair and reasonable cost for extracting or manufacturing said gasoline or other substance*, and ⅛ of the market value of *residue gas* sold or used by lessee in operations not connected with the land herein leased.[63]

However, when the lease provides for a royalty value at or near the wellhead, the lease does not address the deduction of costs–simply because no costs will have been incurred if the valuation is based upon a wellhead sale or value. The same "Bath" form recognizes that if a sale is made at the well, there is no need to address costs: "In the event lessee shall sell gas at the wells, ⅛ of the amount received from such sales." In the event the sale is off of the leased premises, and the lessee does not process the gas,[64] the Bath form provides: "In all other cases when sold or used *off the premises*, the price received *at the well* for ⅛ of the gas sold or ⅛ of the fair value of gas used."[65]

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gas sold or used by lessee in operations not connected with the land herein leased .") (emphasis added).

[62]If it is possible to determine, for example, the "proceeds" or "market value" at the stated location, there will be no need to consider costs the lessee incurs downstream from the stated location. They would not be relevant unless they were used to adjust a downstream price or value to provide evidence of an upstream price or value.

[63]7 Kuntz, *supra* note 3, § 136.5, at 38, ¶ 3.(b) (emphasis added).

[64]The lease states: "In case *lessee shall itself* use gas in the manufacture of gasoline or other petroleum products therefrom . . . ." *Id.* (emphasis added).

[65]*Id.* (a syntactical interpretive issue would be whether the phrase "at the well" is intended to modify "gas sold" and "fair value of gas used") (emphasis added)..

When using a downstream value as a starting point to calculate upstream proceeds or market value, lessees often calculate royalty using the downstream value or proceeds less costs incurred to move the gas from the wellhead to the point of sale or use.[66] When this approach is used, it invites challenges by the lessor regarding whether the individual cost item should be allowed at all and, if so, whether the amount is reasonable.[67]

Relationships Beyond the Oil and Gas Lease

Contracts besides the oil and gas lease may impact the lessor's royalty rights. For example, there may be contracts associated with development of the leased land that impact the royalty obligation, such as pooling agreements, unitization agreements, operating agreements, and gas balancing agreements. Marketing contracts, including gathering and transportation agreements, processing agreements, and production sales agreements, can also impact royalty.

Production Contracts

Pooling Agreements

If the lessees owning leases covering a drilling, spacing, or prorationing unit have adequate pooling authority under their oil and gas leases, a pooled area will typically be formed by triggering the pooling clause of the effected leases through a "declaration of pooling."[68] If the leases in the area to be pooled do not contain adequate pooling authority, all interest owners in the unit area will enter into a "pooling agreement."[69] Because the lessor is a party to the pooling agreement, it is possible to amend the terms of the underlying oil and

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[66]This is often referred to as a "net-back," "work-back," or "cost-netting" method. *See Manual of Oil and Gas Terms, supra* note 10, at 660 ("netback method"); at 1188 ("work-back valuation method").

[67]*See generally* Owen L. Anderson, "Calculating Royalty: 'Costs' Subsequent to Production–'Figures don't lie, but . . . .'" 33 *Washburn L. J.* 591 (1994); Legal Calculus of Post-Extraction Costs, *supra* note 15.

[68]*Forms Manual, supra* note 4, at 233-36 (sample declaration of pooling).

[69]If the parties are not able to agree, the state may provide a statutory pooling option. *E.g.*, Okla. Stat. Ann. tit. 52, § 87.1 (West Supp. 2003).

gas lease. For example, a consolidation agreement[70] used to voluntarily pool leased lands in the Kansas Hugoton Field provides:

> Lessee is hereby authorized by Lessors to connect such gas well or wells as may be completed on the Consolidated Area and deliver gas therefrom on such terms and to such pipe line or pipe lines Lessee may choose, including pipe lines of Lessee, and the gas from said well or wells shall become the property of the Lessee at the mouth of the well. *The parties hereto agree that the royalty payable by Lessee for gas taken into Lessee's pipe lines from the Consolidated area shall be one-eighth (1/8) of four (4) cents per thousand cubic feet, calculated upon a basis of 16.4 pounds per square inch absolute pressure and at a temperature of sixty (60) degrees Fahrenheit, computed in accordance with Boyle's Law governing pressure and volume of gases and at a flowing temperature of sixty (60) degrees Fahrenheit, assumed and agreed upon for the purpose of this contract; provided that if and when Lessee shall sell gas at the well Lessor's royalty thereon shall be one-eighth (1/8) of the proceeds from the sale thereof.*[71]

The italicized language indicates the importance of carefully reviewing all pooling agreements to determine if they contain terms seeking to harmonize the various royalty provisions of the pooled leases by creating a single, uniform royalty obligation for production from the pooled area.

Unit Agreements

When acreage is consolidated on a field-wide basis, lessors will often be a party to the unit agreement.[72] As with the pooling agreement, the terms of the unit agreement must be carefully reviewed to determine the extent to which the underlying oil and gas leases are modified. The American Petroleum Institute's model form of unit agreement modifies the underlying leases to the extent necessary to allocate to each lessor and lessee their proportionate share of unit

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[70]In the Kansas Hugoton Field pooling agreements are often titled: "Consolidation Agreement" or "Unitization Agreement." However, they function as pooling agreements to "consolidate" or "unitize" lands within a 640-acre area for gas development.

[71]Consolidation Agreement covering lands in Grant County, Kansas (emphasis added).

[72]*E.g.*, *Forms Manual*, *supra* note 4, at 264-85 (unit agreement).

production,[73] but the royalty on such production will be calculated pursuant to the terms of each individual lease.[74] The royalty calculation terms between the lessor and lessee are addressed in the section of the unit agreement titled "Distribution Within Tracts" and provides, in part:

> The Unitized Substances allocated to each Tract shall be distributed among, or accounted for to, the parties entitled to share in the production from such Tract *in the same manner, in the same proportions, and upon the same conditions as they would have participated and shared in the production from such Tract, or in the proceeds thereof, had this agreement not been entered into*, and with the same legal effect.[75]

Therefore, if the lease comprising Tract A provides for a 3/16ths royalty calculated on the proceeds received from the sale of residue gas at the tailgate of a processing plant, and the lease comprising Tract B provides for a 1/8th royalty calculated on the market value of gas at the well, each lease must be consulted to determine each lessor's royalty. The unit agreement does not

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[73]Under the model form the "unitized substances" are allocated to the individual "tracts" which typically correspond to a single oil and gas lease. Each tract (lease) is then assigned the percentage by which it will participate in production from anywhere within the unit area. Article 6 provides: "The amount of unitized substances allocated to each tract, regardless of whether the amount is more or less than the actual production of unitized substances from the well or wells, if any, on such tract, *shall be deemed for all purposes to have been produced from such tract*." *Forms Manual, supra* note 4, at 271, model form of unit agreement, Article 6, § 6.1 (emphasis added). This takes care of all the operational issues to ensure individual leases are maintained by production anywhere from within the unit area.

[74]Unlike the previously discussed "consolidation agreement," the base royalty provisions in the unitized leases are not changed by the model form of unit agreement, which states: "The provisions of the various leases, agreements, division and transfer orders, or other instruments pertaining to the respective Tracts or the production therefrom are *amended to the extent necessary to make them conform to the provisions of this agreement, but otherwise shall remain in effect*." *Forms Manual, supra* note 4, at 269, model form of unit agreement, Article 3, § 3.3 (emphasis added).

[75]*Forms Manual, supra* note 4, at 271, model form of unit agreement, Article 6, § 6.2 (emphasis added).

homogenize or otherwise change the base royalty obligation.[76]

Operating Agreements and Gas Balancing Agreements

Unlike pooling agreements and unit agreements, lessors are typically not parties to operating agreements or gas balancing agreements; instead it will be the lessees who are parties to these agreements. Therefore, royalty rights and obligations under the oil and gas lease will not be amended by the terms of an operating or gas balancing agreement. However, it will frequently be necessary to determine how an event defined by, or dictated by, an operating or gas balancing agreement impacts the interpretation of the oil and gas lease royalty clause.[77] For example, if a party is not taking their share of the gas under an

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[76]This is subject to one exception in the event the lease provides for a sliding-scale royalty based upon the volume of production from a well or wells on the lease. Since the process of unitization may eliminate production from certain tracts, while concentrating it in wells on other tracts, the Unit Agreement provides:

> Any royalty or other payment which depends upon per well production or pipeline runs from a well or wells on a Tract shall, after the Effective Date, be determined by dividing the Unitized Substances allocated to the Tract by the number of wells on the Tract capable of producing Unitized Substances on the Effective Date; however, if any Tract has no well thereon capable of producing Unitized Substances on the Effective Date, the Tract shall, for the purposes of this determination, be deemed to have one such well thereon.

Forms Manual, supra note 4, at 271, Model Form of Unit Agreement, Article 6, § 6.2.

[77]*See generally* Ernest E. Smith, "Gas Marketing by Co-Owners: Disproportionate Sales, Gas Imbalances and Lessees' Claims to Royalty," 39 *Baylor L. Rev.* 365 (1987); Ernest E. Smith, "Royalty Issues: Take-or-Pay Claims and Division Orders," 24 *Tulsa L. J.* 509 (1989); Eugene Kuntz, "Gas Balancing Rights and Remedies in the Absence of a Balancing Agreement," 35 *Rocky Mtn. Min. L. Inst.* 13-1 (1989); David E. Pierce, "The Law of Disproportionate Gas Sales," 26 *Tulsa L. J.* 135 (1990).

operating agreement,[78] while the other party is taking 100% of the gas stream,[79] what is the impact on each lessee's royalty obligations?[80]

Will the situation be any different if the parties have entered into a gas balancing agreement addressing the matter? The Rocky Mountain Mineral Law Foundation Form 6 Gas Balancing Agreement states:

> At all times while gas is produced from the Contract Area, each party agrees to make appropriate settlement of all royalties, overriding royalties and other payments out of or in lieu of production from which such party is responsible *just as if such party were taking or delivering to a purchaser such party's full share, and such party's full share only, of such gas production* exclusive of gas used in operations, vented or lost, and each party agrees to indemnify and hold each other party harmless from and [sic] all claims relating thereto.[81]

Although this states the terms that will govern the parties to the gas balancing agreement, lessors are rarely parties to such agreements. Whether the disproportionate take is being made pursuant to an operating agreement, or a gas balancing agreement, the terms of the oil and gas lease will determine the royalty obligation. Similarly, the terms of any assignment creating an overriding royalty, or the terms of the deed conveying a non-participating royalty, must be examined to determine their royalty rights.

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[78]There could be a number of legitimate reasons for a failure to take, such as an inability to transport or sell gas.

[79]This is permitted by most operating agreements which provide in some form that: "Each party shall take in kind or separately dispose of its proportionate share of all Oil and Gas produced from the Contract Area." *Forms Manual, supra* note 4, at 134, lines 27-28, A.A.P.L. Form 610-1989, Model Form Operating Agreement, Art. VI. §G, Option No. 2.

[80]Will the party taking more than its proportionate share of the gas stream have to pay royalty to its lessor on all the gas it takes? Will the non-taking party have to pay royalty on production it is not taking?

[81]*Forms Manual, supra* note 4, at 159, ¶ 10, lines 1-7, Rocky Mountain Mineral Law Foundation Form 6, Gas Balancing Agreement.

Marketing Contracts

This category of agreements includes any contract used to do something with the production once it is extracted. Most contracts can be placed into one of five major categories: sales, gathering/transportation, treatment, processing, and marketing.

Sales Agreements

This category includes any agreement designed to transfer title to oil or gas in exchange for money or other consideration.[82] The sales contract becomes particularly important when the royalty is to be determined employing an "amount realized" or "proceeds" calculation. When the sales contract defines part of the royalty equation, courts will scrutinize the lessee's actions in entering into a particular contract.[83] However, when the lease provides for a royalty measure equal to a share of the oil produced, or the market value of the gas produced, the lessee's sales contract is not associated with the royalty calculation—at least not the "value" component.[84]

Sales contracts are among the most varied formats of agreements used in the oil and gas industry.[85] Although there has been an attempt to provide some recommended formats for short-term gas sales,[86] most contracts have evolved within a company through time—responding to the changes in the regulatory and marketing environments noted above, pp. 9-13.

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[82]"Other consideration" could include delivery of oil or gas at another location in exchange for the oil or gas being sold. This is commonly referred to as an "exchange agreement." *Manual of Oil & Gas Terms, supra* note 10, at 354 ("An agreement by one company to deliver oil or gas to another company at a specified location in exchange for oil of gas to be delivered by the latter to the former company at another location.").

[83]*E.g., Amoco Production Co. v. First Baptist Church of Pyote*, 579 S.W.2d 280 (Tex. Ct. App. 1979).

[84]The contract could, however, impact the "volume" component of the royalty obligation regardless of how the "value" component is to be determined. For example, the contract could impair the lessee's ability to currently produce and sell the maximum volume of oil or gas from the leased land.

[85]For oil sales, the "division order" is often the sales contract. Division orders are addressed below, p. 30.

[86]*See, e.g., Forms Manual, supra* note 4, at 176 ("Base Contract for Short-Term Sale and Purchase of Natural Gas," prepared by the Gas Industry Standards Board, Inc.).

Gathering/Transportation Agreements

Often the lessee will desire, need, or be forced by circumstances, to move oil or gas from the place where it is produced to some downstream location. When the transportation takes place prior to delivery into an interstate or intrastate pipeline,[87] it is commonly referred to as "gathering."[88] Whether referred to as gathering or transportation, the process is essentially the same and consists of all acts incidental to receiving, moving, and re-delivering oil or gas.

Movement through the pipeline system can require compression, dehydration, and other associated actions. Much royalty litigation has focused on the dis-aggregation of the transportation function into "gathering" transportation, as distinguished from "main line" transportation, and the acts necessary to accomplish the movement of gas in a pipeline system: such as compression and dehydration. The sometimes tortured approach to labeling the activity is illustrated by the Kansas Supreme Court's opinion in *Sternberger v. Marathon Oil Company*[89] where the court held Marathon could deduct what were clearly "gathering" expenses when calculating "the market price at the well" for royalty purposes.[90] However, in an apparent attempt to harmonize

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[87]Typically the "interstate" or "intrastate" pipeline designation is used to identify pipeline systems, regulated as public utilities under federal or state law, engaging in the business of moving gas between points within a state or from state-to-state.

[88]*E.g.*, *Manual of Oil & Gas Terms*, *supra* note 10-, at 449 ("A term which 'refers to the process of collecting gas at the point of production (the wellhead) and moving it to a collection point for further movement through a pipeline's principal transmission system. It should be pointed out, however, that the flow of the gas 'is continuous from the well head to the ultimate consumer.'").

[89]894 P.2d 788 (Kan. 1995). *See* "Renaissance," *supra* note 23.

[90]The facts recited by the court were:

> For the Sternberger wells, the gas was *transported from the wellhead through the gas gathering system* laid by TXO [Marathon's predecessor] to the Kansas Gas & Supply (KG&S) pipeline [an intrastate pipeline system]. TXO then paid a transportation fee to KG&S to transport the gas to the purchaser. The transportation fee TXO paid to KG&S was charged back to the royalty owners. That cost is not in dispute and is not an issue in this case.

Kansas and Oklahoma law under the "Conflict of Laws" portion of the opinion,[91] the court labeled the activity "transportation" and concluded: "Transportation expenses may properly be deducted from royalties where

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Sternberger, 894 P.2d at 792 (emphasis added).

[91] At the time the Oklahoma Supreme Court had not rendered its opinion in *Mittelstaedt v. Santa Fe Minerals, Inc.*, 954 P.2d 1203 (Okla. 1998), so the governing law was *Johnson v. Jernigan*, 475 P.2d 396 (Okla. 1970) ("transportation" costs under "gross proceeds at the prevailing market rate" royalty clause deductible) and *TXO Production Corp. v. Commissioners of the Land Office*, 903 P.2d 259 (Okla. 1994) ("compression, dehydration, and gathering" not deductible under lease requiring payment of royalty "without cost into pipelines"). The Kansas Supreme Court characterized Oklahoma law at the time as follows:

> The *Commissioners* court examined its holding in *Wood* and reconciled *Wood* with its decision in *Johnson*. The court reaffirmed the *Johnson* holding that the lessor shares in the costs of *transportation* where the point of sale occurs off the leased premises. Because the sale in *Wood* occurred on the lease site at the mouth of the well, there were no transportation expenses at issue in *Wood*. Rather, at issue were compression costs. The *Wood* court held that compression was not analogous to transporting and compression costs were therefore not deductible where compression was necessary to make the product marketable. . . .
>
> Relying on *Wood*, the *Commissioners* courts held that dehydration is necessary in order to make the product marketable and that gathering also occurs before the product is placed in the purchaser's pipeline; therefore, these expenses, like compression, are not deductible. . . .

Sternberger, 894 P.2d at 803. In *Mittelstaedt* the Oklahoma Supreme Court reconciled the analysis in *Commissioners*, *Wood*, and *Johnson*, by holding:

> [A] royalty interest may bear post-production costs of transporting, blending, compression, and dehydration, when the costs are reasonable, when actual royalty revenues increase in proportion to the costs assessed against the royalty interest, when the costs are associated with *transforming an already marketable product into an enhanced product*, and when the lessee meets its burden of showing these facts.

Mittelstaedt, 954 P.2d at 1210 (emphasis added). Therefore, under Oklahoma law once a "marketable product" is achieved, any post-production cost is potentially deductible to calculate the royalty due—unless the lease expressly provides otherwise.

royalties are payable based on market price at the well and where there is no market at the well and transportation to a distant market is necessary."[92]

The terms of the gathering agreement are typically presented in a document prepared by the owner of the gathering system.[93] This will be the document under which the parties will negotiate. There appears to be very little uniformity from company-to-company and often there is no uniformity within a company that has acquired existing gathering systems and their predecessor's contracts. Interstate and intrastate transportation agreements frequently incorporate the terms of a regulatory tariff.[94] In some situations the transportation may be a component of a sales transaction. In those cases the contract may reference a sales price using, for example, a downstream index minus a transportation charge.

Treatment Agreements

Sometimes a lessee will determine it is advantageous to invest in the treatment of production instead of selling it at or near the point of production, typically to an intermediate purchaser or the owner of a gathering system or a treatment facility. In such cases the lessee will enter into a service contract with the owner of the facility where the lessee delivers the production for treatment which is then redelivered following treatment. The major royalty issue[95] concerning treatment contracts is whether the treatment was required to make the production "marketable" or whether it was merely a downstream enhancement of an already marketable product.[96]

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[92]*Sternberger*, 894 P.2d at 806.

[93]*E.g.*, *Forms Manual*, *supra* note 4, at 208-22 ("Natural Gas Gathering Agreement" used by Duke Energy Field Services Inc.).

[94]*See generally*, *Forms Manual*, *supra* note 4, at 225-31 ("Transportation Agreement" used by Duke Energy Field Services Inc.).

[95]This would be the case in states applying some form of "marketable product" analysis.

[96]*See generally* Lynnette J. Boomgaarden, "Interpreting the Royalty Obligation: Where and How Will Royalty be Calculated?" *Special Institute on Private Oil & Gas Royalties* (Rocky Mtn. Min. L. Fdn., September 8-9, 2003).

Processing Agreements

Processing is undertaken to create new products from the gas stream by creating the conditions necessary to recover certain liquid hydrocarbons, which can be fractionated into products such as propane, butane, ethane, and natural gasoline. Processing contracts can be structured as a service, or as a sale.[97] In a sales transaction the lessee is typically compensated with a percentage of the proceeds from the sale of the liquid products and the residue gas. The most common royalty issue concerning processing is whether the lessor is entitled to share in any of the enhanced value associated with this downstream activity.[98] If they are entitled to share in any aspect of processing,[99] the next issue becomes whether any processing costs can be deducted to calculate royalty.[100]

Marketing Agreements

This category includes agreements a lessee might enter into to procure downstream marketing services designed to aggregate, package, shop, and place the lessee's gas with potential buyers. The major royalty issue will be whether the lessor is entitled to share in any downstream marketing benefits and, if so, whether the costs associated with procuring the downstream benefits are deductible when calculating royalty. Frequently there will also be affiliate transaction issues when the downstream marketing services are provided by an affiliate of the lessee.

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[97]*See generally, Forms Manual, supra* note 3, at 186-205 ("Gas Purchase and Processing Agreement" used by Duke Energy Field Services Inc.).

[98]*See generally* Thomas C. Jepperson, "Special Royalty Issues: Royalties When Gas is Processed," *Special Institute on Private Oil & Gas Royalties* (Rocky Mtn. Min. L. Fdn., March 20-21, 2003).

[99]*E.g.*, 7 Kuntz, *supra* note 2, § 136.5, at 38, ¶ 3.(b) ("In case *lessee shall itself* use gas in the manufacture of gasoline or other petroleum products therefrom, ⅛ of the sale price *at the plant of the gasoline or other petroleum products manufactured or extracted therefrom* and which are saved and marketed . . . and ⅛ of the market value of *residue gas* sold or used by lessee in operations not connected with the land herein leased .") (emphasis added).

[100]The same royalty clause provides: "*after deducting a fair and reasonable cost for extracting or manufacturing said gasoline or other substance . . . .*" *Id.*

Division Orders

Division orders have been used to accomplish one or more of four basic goals:

1.) Establish the precise percentage of production the interest owner is claiming in the extracted oil or gas;

2.) Provide additional guidance on how and when the percentage of production will be calculated and paid;

3.) Establish the basic sales relationship between the interest owner and the production purchaser when the interest owner has title to a share of the extracted oil or gas; and

4.) To change the basis for calculating royalty or overriding royalty stated in the underlying document, such as an oil and gas lease, non-participating royalty conveyance, assignment.

Most of the disputes, and the resulting legislation, have focused on the fourth goal where the lessee is attempting to amend the oil and gas lease terms using a division order.[101] The goals expressed in items (1) and (3) above are generally viewed as legitimate and are often incorporated by statute.[102] Goal (2) encompasses situations that are not addressed in the oil and gas lease,[103] but may in any event have a significant impact on the economic interests of the

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[101]When the underlying goal of requiring a division order is to alter the lessor's rights under the oil and gas lease, some courts have refused to give effect to the amending terms. *E.g.*, *Holmes v. Kewanee Oil Co.*, 664 P.2d 1335 (Kan. 1983), *cert. denied*, 474 U.S. 953 (1985) (attempt to change "market value" royalty obligation to a "proceeds" obligation); *Maddox v. Gulf Oil Corp.*, 567 P.2d 1326 (Kan. 1977), *cert. denied*, 434 U.S. 1065 (1978) (attempt to eliminate common law right to interest on unpaid royalty). Many states now provide by statute: "A division order may not alter or amend the terms of the underlying oil or gas lease." Mont. Code Ann. § 82-10-110 (2) (2001).

[102]*E.g.*, Mont. Code Ann. § 82-10-110 (1) provides: "As used in this section, the term 'division order' is limited to mean an instrument executed by the lessor of an oil or gas lease to authorize the sale of [item (3) above] and direct the distribution of proceeds from the sale of [item (1) above] oil, gas, casinghead gas, or other related hydrocarbons."

[103]Although these terms may not "amend" the lease obligations, they could certainly "alter" the terms and thereby come within a prohibition that the division order "may not *alter* or amend the terms of the underlying oil or gas lease." Mont. Code Ann. § 82-10-110 (2) (2001) (emphasis added).

parties. To the extent the division order is limited to the goal expressed in item (1), it should be enforceable.[104]

The erratic jurisprudence regarding the relationship created by the division order[105] can best be explained by first ascertaining the goal the lessee was seeking to accomplish with the division order. If the goal was to protect the lessee from guessing at the lessor's fractional entitlement, or to allow a third-party[106] to purchase the production, chances are a traditional contract analysis will be employed.[107] However, if the goal is to use the division order as a modifying document to change the terms of the lease, courts will most likely reject a contract analysis and find that the document is ineffective to change the lease terms.[108] Sometimes courts will arrive at a middle ground, holding the division order is a contract that will modify the lease, but then deny full effect to the contract terms by permitting revocation—even when the document expressly makes the division order irrevocable.[109]

The basic focus of lessors in this area should be to determine whether there is a real need for a division order[110] and to establish the goal the division order is designed to serve. For the lessee and any third party purchaser, I cannot

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[104]However, if the division order reflects the wrong royalty fraction, and the benefit of the error flows to the party tendering the inaccurate division order, it may have no effect. *Gavenda v. Strata Energy, Inc.*, 705 S.W.2d 690 (Tex. 1986). *See generally* Laura H. Burney, "The Interaction of the Division Order and the Lease Royalty Clause," 28 *St. Mary's L. J.* 353, 373-80 (1997).

[105]Professor Smith has observed that division order jurisprudence suffers from "too many cases saying too many things without clearly articulating the legal theories used." Ernest E. Smith, "Royalty Issues: Take-Or-Pay Claims and Division Orders," 24 *Tulsa L. J.* 509, 535 (1989).

[106]"Third-party" would include anyone that does not already have a contractual relationship with the interest owner, such as a crude oil purchaser.

[107]*E.g.*, *Blausey v. Stein*, 400 N.E.2d 408 (Ohio 1980) (third-party purchaser division order).

[108]*See* cases cited *supra* note 101.

[109]*E.g.*, *Exxon Corp. v. Middleton*, 613 S.W.2d 240, 250-51 (Tex. 1981).

[110]For example, if the lessor does not own any of the gas when it is extracted under the lease, they have nothing to transfer to a purchaser—whether the lessee or a third party. The lessor in such cases should be able to simply demand payment of their royalty in accordance with the terms of their oil and gas lease.

understand why they would ever tender a document with the title "division order."[111] Instead, a third party should structure the transaction as a bilateral contract with an appropriate descriptive title, such as "sale of goods." The lessee should follow the same bilateral contract, sale of goods, approach when purchasing oil from its lessor. If the lessee desires a change in the way gas royalty will be paid under the oil and gas lease, the lessee should seek to negotiate an "amendment to oil and gas lease" which sets out the manner in which the underlying lease is being modified, or supplemented.

Judicial and Legislative Intervention into the Oil and Gas Relationship

Courts and legislatures have, from time-to-time, intervened to modify the oil and gas relationship, usually to protect the lessor's interests in some fashion.

Indirect Judicial Intervention: Interpretation and Implied Covenants

Judicial intervention has taken two forms: interpretation of lease terms; and the addition or modification of obligations through implied covenants.[112] Interpretation generally follows a determination the lease is ambiguous on a matter.[113] However, the ambiguity finding is rarely used to justify the admission of prior negotiations or other extrinsic evidence to resolve the ambiguity. Instead, courts generally recite the canon of construction that any ambiguity is to be resolved against the lessee, assuming the lessee supplied the document that became the oil and gas lease.[114] Once the oil and gas lease is open for interpretation, it provides the court with an opportunity to realign the

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[111]This merely triggers a host of convoluted case law and, increasingly, equally confusing statutory law. However, you cannot merely change the title of the document; you must also address the underlying problem that caused courts and legislatures to react negatively to the "division order."

[112]John S. Lowe addresses implied covenant issues in his paper: "Interpreting the Royalty Obligation: The Role of the Implied Covenant to Market," *Special Institute on Private Oil & Gas Royalties* (Rocky Mtn. Min. L. Fdn., September 8-9, 2003).

[113]The ability to find an ambiguity, being an issue of law for the court, has sometimes been used as a tool to avoid certain lease language. *E.g.*, *Rogers v. Westerman Farm Co.*, 29 P.3d 887, 897 (Colo. 2001) ("market value" & "at the well"); *Gilmore v. Superior Oil Co.*, 388 P.2d 602 (Kan. 1964) ("at the mouth of the well"). "Renaissance," *supra* note 23.

[114]*Canons of Construction*, *supra* note 24, at 105-08. *E.g.*, *Westerman*, 29 P.3d at 901; *Gilmore*, 388 P.2d at 605.

parties' rights and obligations in a manner the court believes is fair.[115]

Another device used to establish and define lease obligations is the implied covenant. The usefulness of the implied covenant to address perceived inequities in the lease relationship will depend largely upon the extent to which the "implied" terms will be directed or limited by the "express" terms of the lease. To the extent the implied covenant is viewed as a general fairness standard to be applied to all leases, courts will not feel constrained by the express terms of the contract being defined and interpreted.[116] If the issue is approached by first identifying what, if anything, is missing from the parties' agreement, and then fashioning an omitted term that is consistent with the express terms of the agreement, the contract will define the parties' rights. Any fairness inquiry in such a case will employ an unconscionability analysis instead of an interpretive process.

These varying approaches to lease interpretation and implied covenants are described by the terms "implied-in-law" and "implied-in-fact." As noted by the Kansas Supreme Court:

> A contract implied in fact is one "inferred from the facts and circumstances of the case" but which is "not formally or explicitly stated in words.". . . It is the product of agreement, although it is not expressed in words. . . . A contract implied in law does not rest on actual agreement. It is a legal fiction created by the courts to ensure justice or to prevent unjust enrichment.[117]

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[115]The problem is that if the contract is not truly ambiguous, the court is merely rewriting the terms of the contract—often to relieve the lessor from what now appears to be a bad bargain. The proper contract analysis regarding an unfair term is the unconscionability analysis. However, rarely will the lease terms at issue be deemed unconscionable under an unconscionability analysis. Therefore, courts, ironically, may be inclined to resort to the very interpretive devices that the unconscionability analysis was developed to avoid. *See* David E. Pierce, "Exploring the Jurisprudential Underpinnings of the Implied Covenant to Market," 48 Rocky Mtn. Min. L. Inst. 10-1, 10-6 to 10-9 (2002) [hereinafter *Jurisprudential Underpinnings*]; *Renaissance*, *supra* note 23.

[116]*E.g.*, *Rogers v. Westerman Farm Co.*, 29 P.3d 887 (Colo. 2001). *Jurisprudential Underpinnings*, *supra* note 115, at 10-16 to 10-20.

[117]*Smith v. Amoco Prod. Co.*, 31 P.3d 255, 265 (Kan. 2001).

Professor Maurice Merrill was the first advocate for the implied-in-law approach because he believed that fairness concerns often required the court to modify the express obligations of the oil and gas lease to protect the lessor. As he stated: "Of course, the implied covenant is a fiction, used like other fictions by the law in order to achieve a desirable result."[118] He advocated a "radical" departure from basic contract law to modify the oil and gas lease to protect lessors. In his words:

> May there not be, in the conditions peculiar to the oil and gas industry and to the leases executed for the purposes of that industry, circumstances affecting the relation of "lessor" and "lessee" *which justify the somewhat radical departures from ordinary rules* which have characterized the decisions upon the implication of covenants?[119]

Recent decisions concerning the implied covenant to market can be rationalized once it is recognized whether the court is pursuing an implied-in-law or implied-in-fact analysis.[120]

Direct Legislative Intervention: Defining the Lease Relationship by Statute

Statutory intervention[121] has generally focused on four royalty-related areas: 1.) information the lessee must provide the lessor concerning the payment of royalty,[122] 2.) timely royalty payment and interest,[123] 3.) the impact of division orders,[124] and 4.) costs that can be deducted to calculate royalty.[125] Some states also have specialized statutory provisions to address a particular

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[118]Maurice H. Merrill, *The Law Relating to Covenants Implied in Oil and Gas Leases* 27 (2d ed. 1940).

[119]*Id.* at 465 (emphasis added). "Renaissance," *supra* note 23.

[120]*Jurisprudential Underpinnings*, *supra* note 115, at 10-9 to 10-11.

[121]Dante L. Zarlengo addresses these statutes in his paper on: "Special Royalty Issues: Statutes Impacting the Calculation and Payment of Royalty," *Special Institute on Private Oil & Gas Royalties* (Rocky Mtn. Min. L. Fdn., September 8-9, 2003).

[122]*E.g.*, N.D. Cent. Code § 38-08-06.3 (1987).

[123]*E.g.*, Colo. Rev. Stat. Ann. § 34-60-118.5 (West Supp. 2002).

[124]*E.g.*, Mont. Code Ann. §82-10-110 (2001).

[125]*E.g.*, Mich. Comp. Laws § 324.61503b (Supp. 2002).

problem. For example, Oklahoma's forced pooling statute addresses how multiple lessors will be accounted to for the sale of pooled production.[126]

Application of Oil and Gas Lease Jurisprudence to Non-Participating Royalty and Overriding Royalty

There are two general schools of thought that impact whether oil and gas lease jurisprudence should be applied to non-participating royalty and overriding royalty interests. One school of thought focuses on the virtue of uniformity of outcome as the driving force;[127] the other focuses on contract law as the unifying force without concern for uniformity of outcome among individual cases.[128] The first school seeks a uniform body of "oil and gas law" principles that will be applied to determine the parties' rights and obligations. The second school is concerned only with consistent application of basic contract principles: considering the context of the parties' contract, what did they mean when they used certain terms and phrases?

Those desiring a uniformity of outcome would readily apply oil and gas lease jurisprudence to define obligations between a grantor and grantee of a non-participating royalty and the overriding royalty retained by a former lessee in a previous assignment of the lease. Those concerned with consistent application of contract principles would argue the "meaning" of the terms in an assignment must be evaluated in light of the surrounding circumstances of *that* transaction—not some general understanding of the circumstances under an hypothetical oil and gas lease transaction.[129] For states that treat implied

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[126]Okla. Stat. Ann. tit. 52, §87.1(e) (West Supp. 2003).

[127]*E.g.*, Owen L. Anderson, "Royalty Valuation: Should Overriding Royalty Interests and Nonparticipating Royalty Interests, Whether Payable in Value or in Kind, Be Subject to the Same Valuation Standards as Lease Royalty?" 35 *Land & Water L. Rev.* 1 (2000).

[128]*E.g.*, *Jurisprudential Underpinnings*, *supra* note 115, at 10-2 to 10-4.

[129]*Compare XAE Corp. v. SMR Property Management Co.*, 968 P.2d 1201 (Okla. 1998) (rejecting application of oil and gas lease implied covenant law to overriding royalty) with *Garman v. Conoco, Inc.*, 886 P.2d 652, 659 n.23 (Colo. 1994) (summarily concluding: "the rationale for application of the covenants to protect the lessor similarly extends to the interest of an overriding royalty owner."). Commenting on the *Garman* case, the Oklahoma Supreme Court stated: "*Garman* . . . applied the implied covenant to market the product to the overriding royalty owners before it, with little discussion of the differences between an overriding royalty and the lessor's royalty."

covenants as "implied-in-fact" the answer would seem to be clear: in some cases courts will imply covenants, in others they will not—depending upon the terms of the underlying agreement.[130]

Conclusions

The royalty value theorem informs us that royalty disputes will continue as long as there is entitlement to "royalty." Because the value of a barrel of oil or Mcf of gas tends to increase as it moves further downstream away from the wellhead, disputes will focus on precisely where in the marketing process royalty should be calculated. Lessors will argue for valuations as far downstream from the wellhead as possible; lessees will argue for valuation at or near the wellhead. Lessors will argue for a cost-free share at the valuation point; lessees will argue for a netting of costs whenever the valuation point is downstream from the wellhead. Lessors will complain when the lessee is not maximizing production from the leased land. Lessors will argue the oil and gas lease creates a very broad relationship that tends to follow the oil or gas downstream from the lease. Lessees will argue that once a barrel of oil or Mcf of gas is extracted from the ground, it is no longer subject to the oil and gas lease—other than the lessee's obligation to either deliver a share of the oil to the lessor or pay the lessor a sum of money based upon the extraction event.

The answer to all of these issues will be determined by the terms of the underlying oil and gas lease, non-participating royalty conveyance, or overriding royalty assignment. These contracts may be modified by a pooling agreement, pooling order, or unit agreement; they may be impacted to varying degrees by sales agreements, division orders, operating agreements, gas balancing agreements, gathering/transportation agreements, treatment agreements, processing agreements, and marketing agreements. The process of defining the contractual rights of the parties will include varying degrees of statutory and judicial intervention. The impact of judicial intervention will depend largely upon a court's willingness to go beyond the express and implied-in-fact terms of the oil and gas lease in an effort to improve the lessor's position under the bargain.

XAE Corp., 968 P.2d at 1205.

[130]This is without regard for whether we would label the agreement an oil and gas lease, non-participating royalty conveyance, or overriding royalty assignment. This approach is consistent with application of basic contract principles to ascertain the parties' intent.

Appendix

A Concise History of Federal Natural Gas Regulation

1911 to 1954 "Regulatory Gap" Period

1911 *West v. Kansas Natural Gas Co.*, 221 U.S. 229 (1911). Oklahoma law prohibiting interstate transportation of gas violates commerce clause.

1924 *Missouri v. Kansas Natural Gas Co.*, 265 U.S. 298 (1924). State public utility commission cannot regulate prices charged in a sale (at wholesale to a local distribution company—"LDC") for resale (by LDC to its retail customers). Rise of the "negative commerce clause."

1935 During formative stages of the Natural Gas Act the commerce clause was interpreted narrowly to restrict federal regulation of "local" activities—such as the production and in-state transportation of oil and gas.

1938 Natural Gas Act of 1938, 15 U.S.C. §§ 717-717w ("NGA").

Federal Jurisdiction:
(1) Interstate transportation and
(2) Sale for resale.

State Jurisdiction:
(1) "Production or gathering",
(2) "Local distribution", and
(3) All other transportation or sale of natural gas.

Public Utility Regulatory Regime:
(1) Entry ("certificate of public convenience and necessity"),
(2) "Cost-of-service" rates and terms of service,
(3) Service obligation, and
(4) Exit ("abandonment").

1954 to 1984 Regulation of Structurally Competitive Natural Gas Sales Markets

1954 *Phillips Petroleum Co. v. Wisconsin*, 347 U.S. 672 (1954). Sale by an independent producer is a "sale for resale" under the NGA. Therefore, the price a producer charges for gas sold to an interstate pipeline, and the terms of the sale, are subject to federal regulation as a public utility. Individual "cost-of-service" rate making.

1968 *Permian Basin Area Rate Cases*, 390 U.S. 747 (1968). Substitute individual rate making with *area-wide* cost-of-service rate making.

1976 *California Co. v. Federal Power Commission*, 426 U.S. 941 (1976). Denying review of shift to *nation-wide* cost-of-service rate making.

1978 Natural Gas Policy Act of 1978, 15 U.S.C. §§ 3303-3432 ("NGPA").

(1) Regulation extended to all "first sales" of natural gas (including *intra*state sales);
(2) Phased deregulation of certain categories of gas (from 1979 through 1987);
(3) Abandoned cost-of-service rate making and replaced it with "incentive pricing" through a schedule of "maximum lawful prices";
(4) Abandoned entry/exit regulation for certain categories of gas;
(5) Removed regulatory impediments for pipelines that wanted to ship gas for other pipeline segments.

1938 to 1978 Segmented Industry Functions

Production: oil and gas companies explore for and extract gas which they sell at or near the field where produced.

Transportation/Merchant: private right to transport gas on pipeline gives pipeline the ability to buy and sell gas with no competition from producers and end-users. (One buyer and reseller, not thousands.)

Local Distribution: LDC buys gas from pipeline for resale to its customers.

1984 to 1994 Federal Energy Regulatory Commission (FERC) Begins the Process of Creating a Competitive Wellhead Market for Gas

Key Elements:

(1) provide *open access* to transportation,
(2) eliminate historical constraints on *demand* for gas, and
(3) eliminate historical constraints on *supply* for gas.

1984 *FERC Order 380.* Liberate demand by eliminating the "minimum bill."

1985 *FERC Special Marketing Programs* ("SMPs"). Provide alternatives to customers able to shop. Held to violate NGA's prohibition on "undue discrimination." *Maryland People's Counsel v. FERC*, 761 F.2d 768 (D.C. Cir. 1985) (*MPC I*, discounted gas prices) and 761 F.2d 780 (D.C. Cir. 1985) (*MPC II*, access to transportation).

1985 *FERC Order 436.* Provide open access to interstate pipelines for all customers willing to pay the shipping fee; also provided for various demand and supply liberating programs.

1987 Repeal portions of *Powerplant and Industrial Fuel Use Act* liberating demand for gas (allowing it to be used as a fuel in major fuel burning facilities).

Repeal portions of *NGPA* which required "incremental pricing" of gas which would make it less attractive (more expensive) as a fuel source.

1987 *FERC Order 451.* Liberate supply by creating a process to obtain the voluntary release of above- and below-market gas from long-term contracts.

1988 *FERC Order 490.* Eliminate exit (abandonment) requirements for producers.

1989 *Natural Gas Wellhead Decontrol Act of 1989*, Pub. L. No. 101-60, 103 Stat. 157 ("NGWDA"). As of January 1, 1993 phases out all NGPA gas price regulation and NGA gas sales entry/exit regulation.

1992 *FERC Order 636.* Complete open access and eliminate pipeline's merchant role.

1993 All federal gas price and gas sales regulation terminated by NGWDA.

1994 FERC begins the process of allowing interstate pipelines to "spin-down" (sell to an affiliate) or "spin-off" (sell to non-affiliated buyer) gathering systems that were previously operated as part of the interstate pipeline.