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ROYALTY ISSUES IN THE 80's AND 90's

by

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I. YOU ARE IN THE OIL AND GAS BUSINESS

A. Significant Investment To Oversee.

1. Most royalty owners fail to actively manage their oil and gas assets.

2. Importance of organizations like the Southwest Kansas Royalty Owners Association.

B. Developer/Lessee View Of The Royalty Owner:

1. Passive nonparticipant.

2. Does not share in the risk of development.

3. Not necessary to consult royalty owner when making basic lease management decisions.

II. THE BASICS

A. The Oil And Gas Lease.

1. Owner of mineral rights [the "lessor"] grants a developer [the "lessee"] the right to enter land to explore for and produce oil and gas. The mineral rights owner still owns all the mineral rights, but his ownership rights are restricted by limitations agreed to in the oil and gas lease.

2. Oil and gas lease is a contract which specifies the rights of the mineral owner and developer while the contract is in effect.

3. Developer given the exclusive right to develop the property and produce oil and gas.

4. Primary compensation for the mineral owner - the prospect of royalty.

5. To generate royalty, must have successful development and marketing of production.

B. Royalty Clause.

1. Portion of the oil and gas lease which addresses how the mineral owner's share of production will be determined.

2. Commonly a cryptic statement.

   a. Difficult to determine how production should be valued.

   b. Difficult to determine at what point in the production and marketing process the valuation should be made.

   c. Difficult to determine what costs may be deducted from the mineral owner's share of production.

3. The interpretive process:

   a. Developer, without input from the mineral owner, interprets the lease (which was probably a form selected by the developer). As might be expected, this interpretation resolves all doubts in favor of the developer.

   b. Kansas courts recognize the mineral owner seldom has much input in selecting the language used in the lease - although <u>all</u> matters addressed in the lease are initially (prior to signing) subject to negotiation.

      (1) Ambiguities in the lease are interpreted against the developer and in favor of the mineral owner.

      (2) A developer acting in a manner adverse to the interests of their mineral owner is at risk unless there is express language in the lease authorizing the action.

C. Implied Covenants.

1. Lease typically does not address matters such as the degree or rate of exploration and development. Lease does not expressly state the developer's obligation to market production or protect the lease from drainage.

2. When the lease fails to address such matters, courts will <u>imply</u> lease terms which they believe promote the basic goals of the parties to the lease relationship.

a. Typical oil and gas lease suggests the developer will attempt to develop and produce the lease to generate production from which the mineral owner will receive a royalty.

b. Developer must act in a manner that, "in the circumstances, would be reasonably expected of operators of ordinary prudence, having regard to the interests of both lessor [mineral owner] and lessee [developer]."

3. Implied covenants recognized by Kansas courts:

a. Drill an initial well (usually negated by the express terms of the lease - developer pays delay rental in lieu of drilling).

b. Diligently explore the lease.

c. Diligently develop the lease.

d. Market production after discovery.

e. Protect the lease against drainage.

f. Operate and manage the lease efficiently.

C. Implied Covenant To Market.

1. Court-made standard for what the developer must do to market production from the lease.

2. After discovery of oil or gas the developer has the implied obligation to diligently produce and market production from the lease.

3. When well shut in the developer's obligation is "to diligently search for a market and to otherwise conduct himself as would a reasonable and prudent lessee under the same or similar circumstances."

a. May also be obligated to seek administrative or other forms of relief to prevent drainage when adjacent wells are able to produce.

b. Covenant of efficient operation - required to push the right regulatory (and non-regulatory) buttons at the right time to protect the collective interests of the developer and mineral owner.

D. Relationship Created By Oil And Gas Lease.

1. Developer and mineral owner obligated to act "honestly and fairly" toward each other.

2. Developer must act as a reasonable person would act when promoting the interests of the developer and the mineral owner.

3. Developer cannot trade or sacrifice mineral owner's interests to better developer's position.

E. Sale Of Production.

1. Oil - mineral owner, through the lease royalty clause, typically given the right to take oil in kind. If the mineral owner fails to make arrangements to take in kind, developer has implied authority to sell oil and account to mineral owner.

   a. Oil can be readily sold when produced. Can be easily stored and transported.

   b. Short-term contracts used to make oil sales. Sale price (proceeds) usually reflect the current market value of the oil.

2. Gas - developer, through the lease royalty clause, typically given the right to sell gas and account to mineral owner.

   a. Gas cannot be readily sold when produced. Must have pipeline willing to take the gas before it can be produced and marketed.

   b. Traditionally, long-term contracts have been used to sell gas. Contract price may have no relation to the current market value of the gas.

   c. Developer often limited to a single purchaser for the gas. Sales occur in the field where the gas is produced; most often at the wellhead.

3. Sale of production involves two other contracts: the division order and the gas sales contract.

4. Division Order - Oil.

   a. Used by purchaser as the contract with the mineral owner to purchase mineral owner's share of production.

b. Always indicates the mineral owner's interest in production; the share for which the mineral owner will be paid.

c. Often includes other provisions which can reduce the amount payable to the mineral owner - transportation charges, water and gravity adjustments, etc.

6. Division Order - Gas.

a. If developer is making payments directly to the mineral owner, no need for a division order from the mineral owner. This assumes the oil and gas lease clearly gives the developer the right to market the mineral owner's share of production.

b. Often used by developer to try and amend the underlying oil and gas lease. This will not work in Kansas.

7. Gas Sales Contract.

a. Contract between developer and gas pipeline company. Mineral owner not a party to the contract - although the contract directly affects the mineral owner's interests.

b. Depending upon the wording of the royalty clause in the oil and gas lease, the gas sales contract may establish the basis for payment of royalty.

OIL & GAS LEASE	DIVISION ORDER	GAS SALES CONTRACT
Mineral Owner/ Developer	Mineral Owner/ Purchaser [and/or Developer]	Developer/Pipeline Purchaser
Royalty Clause Implied Covenants	Deductions from Royalty	Developer Benefits Developer Commitments

III. APPLYING THE BASICS TO CURRENT GAS ROYALTY ISSUES

A. How Do We Determine The <u>Value</u> Of Production To Calculate Royalty?

1. Begin by examining the royalty clause of the oil and gas lease.

2. Three types of royalty clauses commonly found in Kansas oil and gas lease forms:

a. Market Value - requires payment of royalty based upon the value of the gas when produced.

"To pay the lessor one-eighth, at the market price at the well for the gas so used . . . ."

The problem is determining the "market value" of the gas when sold.

b. Proceeds - requires payment of royalty based upon a stated share of the money (proceeds) the developer receives from an actual sale of production.

"The lessee shall pay lessor, as royalty, one-eighth of the proceeds from the sale of gas, as such, for gas from wells where gas only is found . . . ."

The problem is determining what are "proceeds" which must be shared with the mineral owner.

c. Waechter - valuation of royalty is by proceeds or market value depending upon the point where the gas is sold.

"Lessee shall pay lessor monthly as royalty on gas marketed from each well one-eighth (1/8) of the proceeds if sold at the well, or if marketed by lessee off the leased premises, then one-eighth (1/8) of the market value thereof at the well."

3. In Kansas, a developer cannot amend the royalty clause by obtaining mineral owner's signature on a division order.

4. Can a developer, through agreements with its gas purchaser in the gas sales contract, control the effect of a Waechter royalty clause?

a. Developer could sell gathering system to gas purchaser so that the sale would occur "at the well" to permit payment of royalty on a proceeds basis. Contract could simply provide for delivery at the well.

b. Court of Appeals for the Fifth Circuit, in Piney Woods Country Life School v. Shell Oil Co., 726 F.2d 225 (5th Cir. 1984), suggests the point of sale created by the developer and the gas purchaser in the gas sales contract may not be determinative.

5. Battle to establish right to market value won in the 70's and 80's.

   a. Market value means the value of the gas, when produced, in a "free market."

   b. Not limited by prices established by gas sales contract between developer and gas purchaser.

   c. Not limited by gas price limiations imposed by federal regulation.

6. Potential battle of the 80's and 90's.

   a. Can the developer pay royalty based upon market value when the current market value is <u>less</u> than the price being paid under the gas sales contract?

      (1) All the cases litigated to date have been brought by royalty owners when the market value <u>exceeded</u> the amount being paid under long-term gas sales contracts.

      (2) In <u>Piney Woods Country Life School</u> <u>v.</u> <u>Shell Oil Co.</u>, 765 F.2d 225 (5th Cir. 1984), cert. denied, 105 S.Ct. 1868 (1985), the court observes in a footnote:

      "If the price of gas declines, a market value royalty clause would benefit a lessee who has contracted to sell gas at a favorable price."

   b. Kansas cases do not limit determination of market value to situations where market value exceeds value of the proceeds.

      (1) The Kansas approach would seem to allow the developer to use the lower, market value figure, to calculate royalty.

      (2) In effect, the developer has been forced to assume the risk if his gas sales contract does not keep pace with market prices. Shouldn't the developer enjoy the benefits of his willingness to assume the risk? Especially when it is at no risk to the lessor?

   c. In the 70's and 80's we saw developers having to pay royalty based upon current market value, for example $3.50/MCF, when their long-term gas contract only permitted them to receive $1.50/MCF

for the same gas.

In the 80's and 90's we may see the developer, who entered into long-term contracts during the late 70's and 80's, receiving $3.50/MCF for their gas but paying royalty based upon the current market value of the gas, perhaps a $1.50/MCF or less.

d. The developer will be more inclined to pay royalty based upon market value as a true "free market" for gas emerges. We may ultimately see a "posted price" for natural gas.

B. Determining Value Based Upon Proceeds.

1. What are proceeds? I get 1/8th of what?

2. I predict Kansas courts will view proceeds broadly to include any benefit the developer has received in exchange for the gas.

   a. A broad interpretation could include any right granted to the developer under the gas sales contract.

   b. This could include payments or settlements received under the take-or-pay provisions of the gas sales contract. It could also include such things as severance tax reimbursements and the value of rights reserved to the developer to process liquids from the gas stream.

3. Using a proceeds royalty formula also places an additional duty on the developer to take the action necessary to obtain the maximum benefits possible under the gas sales contract. I wonder if the developer has an obligation to get the best deal under a market value royalty clause? Guaranteed rates of take may be more important to the market value royalty owner than the price paid for the gas.

4. The developer cannot trade-off rights under one contract for benefits under other contracts. For example, foregoing rights under a take-or-pay provision under gas contract A in return for the gas purchaser agreeing to increase gas takes under contract B.

   a. Most developers, innocently, view such matters as a business decision within their sole discretion.

   b. However, if the decision will adversely impact one of their lessor/mineral owners, they violate their

obligations under the oil and gas lease.

Amoco Production Co. v. First Baptist Church of Pyote, 579 S.W.2d 280 (Tex. Civ. App. 1979), writ ref'd n.r.e., 611 S.W.2d 610 (1980).

C. Royalty Formula For New Leases.

1. Mineral owner wants the best that market value and proceeds have to offer.

2. Provide for an amount equal to the greater of:

(1) the gross proceeds from the sale of gas; or
(2) an amount equal to the market value of the gas.

3. Specifically address mineral owner's right to the enhanced value of gas after processing and the mineral owner's obligations to share in the cost of processing or other post-production activities.

D. At What Point In The Production And Marketing Process Should Value Be Determined?

1. Many royalty clauses specify that production will be valued, or proceeds determined, "at the well." However, if it is not clearly stated where the valuation point will be, the mineral owner can argue they are entitled to a share of the proceeds or market value at the point where the first sale occurs.

2. The developer may decide to process the gas, before it is marketed, to remove liquid hydrocarbons. Generally the value of the "dry" residue gas and the separated liquid hydrocarbons is much greater than the "wet" unprocessed gas.

a. If a sale of the liquids and residue gas occur after processing, and the royalty clause does not require valuation "at the well," the mineral owner has an argument that "proceeds" or "market value" should be determined at the time of the actual sale.

b. If the processing is done after a sale, but pursuant to a redelivery and processing right retained in the gas sales contract, the mineral owner has an argument the redelivery and processing right is a "proceed" of the gas sale.

This assumes the developer had to give up other rights, such as a higher per unit price for the

wet gas, to "buy" the right to process the redelivered gas.

E. What Costs Can Be Charged Against The Mineral Owner's Share Of Production?

1. Royalty generally defined as a cost-free share of production paid or delivered to the lessor/mineral owner.

2. "Cost-free" refers to costs associated with drilling, completing, and producing the well. However, mineral owner may be assessed a share of costs incurred after production.

   Problem in Kansas is determining where the cost-free production function ends and the cost-bearing post-production function begins.

3. Law in Kansas uncertain.

   a. Early Kansas cases permit developer to deduct the cost of transporting production to a market.

   b. More recent cases, although not directly addressing the issue, cast doubt on whether transportation and other marketing costs are deductible - UNLESS expressly permitted by the terms of the oil and gas lease.

   c. In Kansas, without express authorization in the lease, the developer cannot deduct "compression costs" when calculating royalty.

F. Payment Of Royalty.

1. Need for basic information to allow mineral owner to have some idea: how much oil and gas were produced and sold during the payment period, how much it was sold for, what deductions were charged against the mineral owner, and the value attributable to the production.

2. Mineral owner often gets a check with little or no explanation how the figures were determined.

3. No statutes in Kansas. See the Oklahoma check stub law - Okla. Stat. Ann. tit. 52 §§ 567 and 568 (West 1987).

4. Mineral owner cannot protect their rights without accurate information - information which is generally controlled by the developer and not volunteered to the mineral owner.

IV. ROYALTY ISSUES IN THE NEW FEDERAL REGULATORY ENVIRONMENT

A. Federal Energy Regulatory Commission Initiatives.

1. Strong commitment to deregulate the gas industry to facilitate competition. See generally FERC Strives to Untangle Knots in U.S. Natural Gas Industry, 85 Oil and Gas Journal 15 (April 20, 1987).

2. Recognize gas as a commodity instead of a service.

3. FERC's transitional measures to aid the shift from a regulated to a deregulated industry: Order 436; Order 451; Take-or-pay Strategy.

B. Order 436.

1. Releases gas consumers (end user, local distribution companies "LDCs") from reliance upon the pipeline for their gas supply.

   a. Ability to convert their gas supply contracts with the pipeline to transportation rights.

   b. Once released from the pipeline as their sole supplier, they can shop around for gas and, with their transportation rights, have a way to get the gas from the field to the end user.

   c. This opens up new markets for gas.

2. Opens access to pipeline transportation services.

   a. Traditional role of pipeline - pipeline bought the gas at the producer end of the pipe and then resold it at the user end of the pipe.

   b. This merchant function is retained by Order 436, but the pipeline is required to "unbundle" its services and make them available for purchase.

   c. Major service being unbundled is transportation.

   d. Goal is to provide nondiscriminatory transportation of gas from point of production to point of use.

3. Makes it easier to construct new pipelines.

4. Allows the users of gas to shop for the best commodity (gas) and transportation deal. Competition for commodity price and traditional pipeline services

(backup supply, storage, etc.).

a. Unbundle sale of gas from pipeline services - allow consumer to determine whether pipeline is the place to buy gas or whether it is reasonable to purchase from a gas marketer or producer.

   Also permits using multiple suppliers to meet gas needs. May be safer using short-term contracts when there are more suppliers and competition between suppliers.

b. Allows the pipeline customer, whether producer or end user, to purchase only the services they need from the pipeline. For example, gathering, transportation, storage, standby service.

5. General problems under Order 436:

   a. Limited capacity. Allocation of capacity and curtailment.

   b. Pipelines reluctant to go into a transportation role without being relieved of the baggage it accummulated when functioning in a merchant role - take-or-pay obligations. Existing obligations under long-term gas contracts. Order 436 releases some of the pipeline's markets. Order 451 is designed to relieve pipeline obligations to the producer. FERC's take-or-pay strategy designed to deal with some of the baggage.

6. Royalty Issues Under Order 436.

   a. Developer will have options when marketing gas.

   b. Options impose new obligations on the developer. Must be careful that the marketing arrangement which appears most beneficial to the developer does not adversely affect their mineral owner.

   c. Developer must develop expertise, or hire expertise, to make proper marketing decisions.

   d. Will the gas marketer's 2% commission be deducted before calculating the mineral owner's royalty? Is this a <u>cost</u> that can be deducted in calculating royalty?

   e. Will the gathering, transportation, and similar "unbundled" charges be deducted in calculating royalty?

Will they be hidden by arranging for the end user to buy the gas at the wellhead for a cheaper unit price which equals the commodity value less gathering, transportation, and similar charges?

f. Penalties imposed by pipelines under Order 436 settlements: If the developer delivers more gas to the pipeline than their end user takes out, the excess gas becomes the property of the transporting pipeline. Will a royalty be due on this penalty gas?

g. At what point will the gas be valued for royalty purposes? Will the point of sale stated in the developer/end user contract be determinative for royalty purposes?

C. Order 451.

1. Facilitate commodity (gas) price competition at the wellhead.

2. Once the gas is given access to markets, and existing long-term contracts adjusted to reflect current market value of the gas, a competitive market for gas can develop.

3. Provides a framework for negotiation between developer and gas purchaser (pipeline) so they can:

   a. Increase old gas (NGPA §104 and §106 gas) prices up to a single alternative maximum lawful price (AMLP) which is currently in the range of $2.60/MMBTU.

   b. Decrease gas prices under gas contracts providing for a high price.

   c. Address other contract issues - such as take-or-pay.

4. The Good Faith Negotiation (GFN) Process:

   ASSUME: Producer has two gas sales contracts with the Purchaser.

   Contract A - covers old gas only, current sales price: $.50/MCF.

   Contract B - covers old gas plus other higher priced gas, average current sales price: $3.00/MCF.

STEP 1. Producer initiates the GFN Process by asking Pipeline to increase the price paid for gas under Contract A.

STEP 2. Pipeline has the right to bring in any other contract they have with the Producer, covering some old gas, and make it subject to the GFN process. Pipeline responds by asking for a lower price on gas covered by Contract B.

STEP 3. Producer may request higher price for old gas covered by Contract B.

STEP 4. If Purchaser agrees to pay the AMLP for the old gas, sales continue at the AMLP.

However, if Purchaser offers a price lower than the AMLP for the old gas (which would probably be the case in today's market), the Producer may accept the lower price and sales continue.

However, if Producer rejects the lower price, sales continue at the old contract price until the Producer terminates the sale.

STEP 5. If Purchaser offers a new price for the high priced gas, the Producer can accept it and sales will continue at the new price.

However, if Producer rejects the reduced price, sales will continue at the old contract price until the Purchaser terminates the sale.

STEP 6. Any gas released because the parties are unable to agree on price can be abandoned and the purchaser will provide access to transportation for a new sale.

5. Royalty Problems Under Order 451.

a. Assume the Purchaser in the previous example offers to renegotiate as follows:

Contract A from $0.50/MCF to $1.75/MCF

Contract B from $3.00/MCF to $1.75/MCF.

Depending upon how much gas is flowing under each contract, and the Producer's net revenue interest under the affected leases, Producer may find it very advantageous to agree to the Purchaser's

proposal.

b. What happens if you are the royalty owner under Contract B and your royalty is calculated on proceeds? Assume a 1/8th royalty, your royalty income per MCF of gas is reduced from $0.37 to $0.22.

c. What happens if you are the royalty owner under Contract A and the Producer refuses to enter into the GFN process? Assume a 1/8th royalty, your royalty income per MCF of gas remains at $0.06 instead of a possible $0.22.

d. Suppose the Producer is unsuccessful at negotiating a better price and the gas is released and shut-in?

e. Should the mineral owner under either contract be penalized because their developer has many contracts with the same purchaser?

f. Recall: Developer cannot trade or sacrifice mineral owner's interests to better developer's position. Amoco Production Co. v. First Baptist Church of Pyote, 579 S.W.2d 280 (Tex. Civ. App. 1979), writ ref'd n.r.e., 611 S.W.2d 610 (1980).

6. May see developers in Kansas, as part of the 451 renegotiation process, buying back gathering lines and changing the point of delivery to a point off the leased premises so they can pay royalty based upon market value under a Waechter type lease royalty clause.

   Recall: Piney Woods Country Life School v. Shell Oil Co., 726 F.2d 225 (5th Cir. 1984).

7. Order 451 presents major royalty problems for developers.

V. DEVELOPERS NEVER LEARN

A. Still Use Lease Forms Which Perpetuate Royalty Calculation Problems.

B. Attitude Toward Mineral Owner Has Not Changed.

C. Mineral Owner Strategy For The 80's And 90's:

1. Know what is going on - find out how your royalty is being calculated so you can protect your interests.

2. Be aware of the potential for developer self-dealing which may adversely affect your interests.

3. In Kansas, "informed ignorance" may be the mineral owner's best approach when developer is making decisions in the "new" gas regulatory climate.

   a. To the extent the developer's decisions are made without the consent of the mineral owner, the mineral owner can contest them when they are adversely impacted.

   b. However, the adverse impact must arise out of either the developer's imprudence or the developer's attempt to subordinate the mineral owner's interests to the developer's self-interest.