

# Royalties Litigation: Fundamentals & Practicalities

**To: Attendees of the Conference on *Royalties Litigation: Fundamentals & Practicalities*, Houston, Texas; Sept. 22, 2015**

I've spent much of the past 15 years in litigation against large oil and gas producers. The disputes have concerned upstream pricing, processing, general production issues, and all aspects of upstream-midstream marketing – specifically, how such activities affect my clients' royalty income or working-interest revenues and related expenses.

The royalty accounting and revenue accounting departments of most large oil and gas producers consist of hard-working, conscientious personnel, who are doing their best to measure volumes for, apply prices to, report taxes on, make allocations for, and distribute money concerning hydrocarbon production. Each month, they have to process copious amounts of data relating to hydrocarbon production, transportation, processing and sales – in order to pay hundreds of thousands, or hundreds of millions, of dollars to royalty owners, working interest owners, and taxing authorities. They may mistakes, but generally are doing their best under the foregoing circumstances. Also, these circumstances challenge their ability to comply with lease royalty-valuation clauses.

This Paper and my speech are sensitive to the demands on royalty accounting and revenue accounting departments and circumstances under which they work. In my experience, whether in litigation or in private negotiations, the best results for royalty owners result from understanding the accounting personnel and their circumstances, and working with them so as to minimize data requests and burdens for them.

I intend to equip Conference attendees with the fundamental principles they must understand in order to conduct efficient royalty-related litigation, either as plaintiff's or defense counsel, or to provide consultation outside of litigation on matters concerning royalty income. My presentation concerns only private royalty interests; it does not address the world of government-owned and government-managed royalty interests. (As an aside, deep insights into oil and gas valuation and royalty accounting can be gained from attending conferences that address the practices of the Office of Natural Resources Revenues and the Bureau of Ocean Energy Management (formerly, Minerals Management Service), especially for royalty owners in "marketable condition rule" states.)

In my practice, I've focused primarily on casinghead gas (*i.e.*, the wet, low-pressure gas associated with crude oil production), crude oil, and gas-well gas, in that order. My practice has become increasingly focused on gas-well gas (*viz.*, Barnett Shale gas) over the past four years.

I currently represent several royalty owner groups in shale-gas litigation pending in Texas federal courts. Much of this litigation concerns Chesapeake's low pricing for its shale-gas royalty payments. Chesapeake and Total entities are defendants in my clients' lawsuits. Although I cannot share confidential information that I've learned via these lawsuits, I can discuss the general legal and factual concepts at play – such as the pleadings and public statements by the parties.

By surveying my own legal practice areas, I hope with this paper and related speech to explore the key concepts that royalty owners must understand in order to dialogue with their producers over oil and gas royalties in any state. Along the way, the paper and speech should equip them with knowledge, arguments and tools to strengthen their negotiation/litigation positions.

James Holmes  
September 2015

James Holmes enjoys a diverse practice of oil and gas cases and business cases. He has substantial trial and appellate experience. James was born, raised and educated in Texas. Before practicing law in Dallas, he earned his Bachelor of Science from Trinity University in San Antonio and his Juris Doctorate from the University of Texas School of Law in Austin, where he served as an Editor on the Law Review and graduated Order of the Coif.

Currently, James represents a royalty owners, bank-operated royalty/mineral trusts, non-operating working interest owners, and surface-estate owners by way of various legal matters in the Barnett Shale and in the legacy oil fields of Texas and New Mexico. Also, when feasible, James will assist in the marketing of his clients' share of production and in pursuing other transactional remedies and work-outs as alternatives to litigation. He has special experience in gas-processing arrangements; the interdependency of gas plants and mature oil reservoirs; cradle-to-grave marketing arrangements for gas-well gas, casinghead gas and crude oil; and enhanced oil recovery via CO<sub>2</sub> flooding and other reservoir-pressure management.

In addition to his law practice, James operates Robur LLC, a crude oil first purchaser and marketer. He also manages Robur Capital, L.P., a value-investing style investment partnership.



# No Peace Under the Lease

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David Pierce, a prominent oil and gas law professor and former practitioner, has correctly observed that “there will never be peace – under the oil and gas lease” because “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.” David E. Pierce, *The Royalty Value Theorem and the Legal Calculus of Post-Extraction Costs* at 152, § 6.01, PROCEEDINGS OF THE TWENTY-THIRD ANNUAL ENERGY & MINERAL LAW INSTITUTE (May 20-21, 2002). Tug-of-wars over royalty valuations are virtually inevitable under every oil and gas lease or sharing arrangement. Royalty disputes become especially prevalent when producers (*i.e.*, lessees) see an economic advantage for themselves in not sharing hydrocarbon value with royalty owners, as is often the case with gas marketing. *See generally* 5 HOWARD R. WILLIAMS & CHARLES J. MEYERS, OIL AND GAS LAW § 856.3, at 411-12 (rev. ed. 2008) (“Where the interests of the [lessee and lessor] diverge and the lessee lacks incentive to market gas, closer supervision of his business judgment will be necessary.”)

Royalty disputes proliferate in the arena of gas royalties, which are operationally more complex than oil royalties and in which royalty owners, under most leases, are entirely dependent upon their producers to market royalty gas. Royalty owners frequently lack the ability to take royalty gas in kind and thereby circumvent their producers’ poor marketing behavior – that is, their producers’ practices of obtaining for themselves hydrocarbon value and not sharing such value with royalty owners. Even when royalty owners can take gas in kind, they typically do not have sufficient volumes to make the endeavor worthwhile. Also, most royalty clauses are too limited in content; therefore, they lack sufficient provisions to anticipate the varied factors that will play

some role in determining gas royalties – consequently giving the producer wide discretion to handle many unknowns. See John McFarland, *Issues Concerning Royalty Valuations and Deductions*, presented at National Oil & Gas Royalty Conference, November 2002, and subsequently published in *PETROLEUM ACCTG. & FIN. MGMT. J.* (Univ. of N. Tex. Inst. of Petroleum Acctg., Fall/Winter 2002, Vol. 21, No. 3) (surveying seven key issues affecting gas-royalty payments and concluding “most royalty clauses” do not adequately address the issues).

Royalty owners must monitor and regulate their producers’ marketing behavior. Among their tools for doing so are the following:

- 1. Seek information.** For instance, use form letters like those attached as “Exhibit A” to this paper in order to ask insightful questions of your producers.
- 2. Attempt negotiation and compromise outside of legal proceedings.** When the concepts discussed in this paper clearly show that according to your lease you’ve been underpaid on gas royalties, then many reputable producers will compromise, give you money for past underpayments, and re-work your future payments to comply with your lease rights.
- 3. Pursue a lawsuit.** Class actions are not feasible in Texas for royalty-owner cases. Efforts to establish venue for Texas royalty-owner classes in states other than Texas appear to have encountered troubles in the courts of those other states. Individual cases are feasible – but require trial and appellate courts that will apply Texas law in a balanced manner, as the law is written, and in favor of royalty-owner rights. Many royalty-owner attorneys, accordingly, are seeking Texas federal courts over state courts because of the poor perception of the Texas appellate system’s treatment of royalty owners over the past 20 years.
- 4. Ride the coattails of government action.** During the 27<sup>th</sup> Annual NARO Convention in Las Vegas in 2009, James Holmes recommended that royalty owners hope for and encourage government action against large producers utilizing bad royalty practices, which could have an “invisible hand” effect of raising oil and gas royalty payments for private interests. For instance, if a state agency or the Minerals Management Service causes a large producer to pay better royalties or production-related taxes in a large lease/unit containing private royalty owners, those private royalty owners may see increased royalties because of the government action, as the producer is forced to apply higher prices on lease/unit production. In Texas it is unlikely that state or county taxing authorities will challenge the gas prices of large Permian Basin, Barnett Shale and Eagle Ford Shale producers. However, if they did so – and thereby obtained higher prices for purposes of severance taxes and ad valorem taxes – their action could result in higher prices on which royalties are paid, benefitting some royalty owners.

The tug-of-wars over royalty valuations between royalty owners and large producers are fights well worth fighting. Texas royalty owners have much to gain financially from enforcing their contractual and case-law rights for higher gas royalties. It is long past time for Texas royalty owners to become both politically minded and legally active in favor of their rights, which have seen far too much curtailment in Texas over the past 25 years. May this paper equip them with some of the knowledge, arguments and tools that they will need in order to strengthen their negotiation/litigation positions, especially as to gas royalties.



# Crude Oil Marketing

(and documents you'll need)

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For private royalty-valuation purposes, crude oil typically is sold at two important points: first, at or near the point of production and, second, at a downstream liquids hub, such as Midland, Cushing or the Gulf Coast. Under most leases, royalty owners actually own title to the crude oil at the point of production, and by way of their division orders they sell immediately to the producer.

The producer moves on pipeline the crude (*i.e.*, “ships the crude”), selling to various arm’s length buyers at the downstream hub. Alternatively, a “first purchaser” unrelated to the producer buys crude at the point of production either from the producer or from the royalty owner and ships it downstream to arm’s length buyers. When shipping, the producer or first purchaser incurs and pays tariffs to gathering systems and pipelines. Most shippers pay common, equal tariffs; however, large-volume shippers can obtain discounted tariff rates.

The crude’s quality (specifically, its sulfur content and “gravity”) in part determines the prices it will fetch at downstream liquids hubs. Generally, the less-sulfuric and “lighter” the crude, the higher price paid for it. (Light sweet crude tends to have higher API numbers – for instance, 38 degrees or higher.) At times, sour (heavier) crude can fetch higher prices than light sweet crude, but the location of sale typically drives the price differential in such instances.

Crude oil sales contracts tend to be short and simple – often consisting of only two or three pages. They specify a price and location for sale; they provide a pricing formula based on an established index price, such as WTI at Cushing (NYMEX) or a major oil company’s “posted price” for a certain region. They typically last month to month.

Important documents will arise from the foregoing crude oil marketing: (i) “LACT” tickets and measurements (*i.e.*, volume data at or near the point of production); (ii) gathering and pipeline statements (showing the volume flow from point of production to downstream sale); (iii) maps and diagrams of gathering and transportation systems; (iv) tariff invoices and payments thereof; (v) a crude oil sales contract at the downstream hub; (vi) evidence of money sales; (vii) highly complex production-tax volume data; (viii) royalty-decimal worksheets to allocate volumes to royalty owners; and (iv) pricing worksheets to calculate BBL prices on which royalties and production taxes are paid. Most of these documents exist in electronic form only, such as Excel files. All such documents must be requested from the producer’s files in order to understand the crude oil marketing that has determined oil royalties.

Sample document requests the author has used in the past include:

*Electronic files and data (such as Excel or Access files) showing Jarvis Christian College’s oil royalties from the Hawkins Field Unit, from 1994 to present.*

*For January 2002, September 2003, January 2004, May 2004, March 2005, March 2006, and each month in 2007: Run tickets (or other statements) showing the gravity, temperature and volumes for the Hawkins-related crude stream at the Hawkins Station.*

*For January 2002, September 2003, January 2004, May 2004, March 2005, March 2006, and each month in 2007: Run tickets (or other statements) showing the gravity, temperature and volumes for the Hawkins-related crude stream at Kilgore.*

...

*All pipeline tariffs from Plains Pipeline and Centurion for the period March 2006-April 2010 showing your shipments from point of production to Midland.*

*The applicable oil-sales contract(s) under which you have sold oil on which Turner Trust has received royalties for the period March 2006-April 2010.*

Inquiry into crude oil marketing, and related document requests, seek to learn whether the royalty owner is receiving the benefit of “net back” pricing: the BBL price on which royalties are paid reflects the downstream BBL sales price, less the various tariffs necessary to ship the crude from point of production to downstream liquids hub.

More difficult marketing scenarios arise when the producer has “cradle to grave” ownership and control of the crude from the point of production to refinery consumption.

The producer may be a large “integrated” company so that it serves as oil producer, first purchaser, shipper, and refiner. An integrated company may even own the pipelines on which the crude travels from point of production to refinery gate. Producers with cradle-to-grave control over a BBL likely will use a pricing formula whereby they attempt to approximate market prices for similar crude; the formula may attempt to reflect a hypothetical scenario in which the crude was bought, shipped and sold by arm’s length companies. Formulas can fail to approximate the “net back” pricing that would result if the crude had been bought, shipped and sold by arm’s length companies.



# Gas Well Gas Marketing

(and documents you'll need)

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Gas well gas is mostly methane. It is produced at *relatively* high pressures and in a state mostly ready for consumption, requiring little treatment or processing. (“Relatively” in relation to associated gas, discussed below.) Gas well gas is not associated with crude oil production.

For private royalty-valuation purposes, such gas typically is sold at two important points: first, at or near the point of production and, second, at a downstream sales point, such as an industrial complex, city gate or electric utility. Under most leases, royalty owners never own title to gas; such ownership remains entirely with the producer, which bears a contractual obligation to market the gas for the royalty owner’s benefit. The producer frequently sells the gas to an arm’s length buyer or to an affiliate, fairly close to the point of production.

The first purchaser then ships the gas on pipeline to a downstream sales point. When shipping, the first purchaser incurs and pays tariffs to gathering systems and pipelines. Such tariffs typically rise or fall depending on the volume shipped. Most shippers pay common, equal tariffs; however, large-volume shippers can obtain discounted tariff rates. Also, shippers can obtain “reserved space” on pipelines in the event they expect to have to ship large gas volumes. Reserved space ensures the producer that a pipeline can take and transport the producer’s expected volumes, so the producer will not have to shut in production or otherwise decrease volumes shipped. Reserved space arrangements are common on interstate pipelines. They give rise to “firm” tariff arrangements, consisting of a “demand” charge that is paid regardless of volume shipped, and a “commodity” charge that fluctuates with the volume shipped. Also, in exchange for a company’s building of a pipeline, or purchasing a pipeline from a

producer, a producer might commit itself to a higher-than-market tariff structure, in order to provide an incentive for the building or purchasing of the pipeline.

In addition to tariff charges, producers must pay “FL&U” charges (“fuel, loss and unaccounted for gas”) to pipelines, or must concede gas volumes to pipelines as a representation of the FL&U activity.

After treatment and pressurization, gas well gas is very similar in quality to gas from other fields. Unlike crude oil, gas does not tend to obtain higher or lower sales prices at downstream points based upon differing qualities.

Gas well gas sales contracts tend to be very lengthy and thorough – often consisting of 30 or more pages. The contracts specify a price and location for sale. They specify gas quality and pressure requirements. They typically last for years, followed by month-to-month “evergreen” renewal. The contracts tend to be lengthy and thorough both for upstream sales (*i.e.*, those occurring at/near production) and downstream sales (*i.e.*, those occurring close to gas consumption) – but for different reasons. Upstream gas sales contracts are lengthy and thorough because they are collateral to, and provide incentives for, the building and maintenance of a gathering system by the gas purchaser, also called the “gas transporter” or “gas gatherer.” Downstream gas sales contracts are lengthy and thorough because they anticipate and account for varying demand, weather conditions, and economic activity affecting consumption. Price terms appearing in gas well gas sales contracts include published index prices (*e.g.*, *Inside FERC* and *Gas Daily* indexes), fixed prices (*e.g.*, “\$3.50/MMBTU for years 2016-2018, \$3.77/MMBTU thereafter . . .”), or Weighted Average Sales Prices (“WASP”) based upon actual sales for a certain region. Price terms typically account for (and are lessened by) the gathering, treating, and transportation charges from production to sales point.

Important documents will arise from the foregoing gas well gas marketing: (i) production volume measurements; (ii) gathering and pipeline statements (showing the volume flow from point of production to downstream sale); (iii) maps and diagrams of gathering and transportation systems; (iv) tariff invoices and payments thereof; (v) gas sales contracts at point of production and at downstream sale; (vi) evidence of money sales; (vii) highly complex production-tax volume data; (viii) royalty-decimal worksheets to allocate volumes to royalty owners; and (iv) pricing worksheets to calculate MCF prices on which royalties and production-taxes are paid. Most of these documents exist in electronic form only, such as Excel files. All such documents must be requested from the producer’s files in order to understand the gas well gas marketing that has determined gas royalties.

Sample document requests, with definitions, the author has used in the past include:

*Excel files (or other database-table electronic files) showing gas royalties paid to Plaintiffs from Feb. 2011 to present.*

*Applicable purchasing and services contracts between the lease operator and Chesapeake Energy Marketing, Inc. (“CEMI”), relating to gas from the lease, including the contract files.*

*Applicable purchasing and services contracts between either the lease operator or CEMI, on one side, and third-party buyers and service providers, on the other side, relating to gas from the lease.*

*Monthly settlement statements for the contracts described in the foregoing request, for the months of Mar. 2011, Feb. 2012, July 2013, Jan. 2014, Apr. 2014 and Nov. 2014.*

*Schematics and diagrams of the gathering system, processing/treatment facilities, compression facilities and transportation system for the gas under the leases at issue, from wellhead production to the point of sale to an unaffiliated party.*

*The agreements by which COI or CEMI or other Chesapeake entity transports gas on the lines of Atmos, ETC, CrossTex and Enterprise, after the initial gathering.*

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*Definitions:*

*“Purchasing and services contract” means gas-sales agreements, gas-handling agreements, gas-processing agreements, gas-settlement agreements, or similar agreements or contractual arrangements, including gas contracts on gas wells, whereby a gas gatherer or plant operator has handled or processed gas-well gas on behalf of lease/unit operators and/or working-interest owners, and whereby the gas gatherer or plant operator would remit to the various lease/unit operators and/or working-interest owners a price per MCF or MMBTU for such production. When Purchasing and Services Contracts are requested, Defendant should produce also the contract briefs or contract summaries.*

*“Settlement Statement” means the monthly or periodic reports by the gas gatherer or plant operator showing the volume and quality of gas sent from a lease/unit to the gathering system or plant. Such Settlement Statements typically show the date of sampling, the sample meter number(s), chromatograph gas analyses, gas volumes, and contract terms (such as per-MCF prices, or per-MMBTU prices). You have received these Settlement Statements in your capacity as gas producer or seller, working-interest owner in a lease/unit, or working interest owner in a plant or gathering system.*

*“Contract File” means the correspondence and related agreements surrounding the formation, negotiation and execution of a purchasing and services contract, as well as the correspondence and related agreements relating to the performance of such contract. Information showing whether the producer/seller owned all or part of the processing plant/facility at the time of contract formation typically appears in the*

*contract file.*

Inquiry into gas well gas marketing, and related document requests, seek to learn whether the royalty owner is receiving the benefit of “net back” pricing: the MCF price on which royalties are paid reflects the downstream MCF sales price, less the various tariffs necessary to ship the gas from point of production to downstream sales point.



# Associated Gas Marketing

(and documents you'll need)

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Casinghead gas, also known as associated gas, is the low-pressure gas associated with crude oil production, which is rich in liquefiable hydrocarbons (ethane, propane, butane, pentanes+, the “NGLs”), and which must be processed close to the point of production. By many degrees, the measurement and accounting for associated gas is more complex than the measurement and accounting for crude oil and gas well gas.

Gas plants have a symbiotic relationship with local oil production: without the plant’s processing services and field support, much of the oil production could not occur. Likewise, but for the gas associated with the oil production, the plant would not receive the liquids-rich gas streams it needs to sustain plant operations. Accordingly, associated gas contracts and marketing must anticipate and account for the symbiotic relationship between oil field and gas plant.

For private royalty-valuation purposes, associated gas typically is sold at one point: at or near the point of production. Under most leases, royalty owners never own title to gas; such ownership remains entirely with the producer, which bears a contractual obligation to market the gas for the royalty owner’s benefit. The producer frequently sells the gas to an arm’s length buyer’s gas plant or to an affiliate’s gas plant, fairly close to the point of production.

The first purchaser moves the gas from point of production to plant inlet. The gas must be processed in the plant; its quality does not allow for lengthy intrastate or interstate pipeline transportation. The gas is rich in liquefiable hydrocarbons, but also contains many contaminants like carbon dioxide, helium, nitrogen and hydrogen sulfide. The gas may contain three, ten or fifteen “gallons per MCF” (“GPMs”), indicating it

carries lots of NGLs. However, the same gas is called “acidic,” “sour” and “contaminated” because it contains substantial inerts. A key document for understanding the nature and content of a gas stream feeding a plant is the plant’s monthly settlement statement, which memorializes the gas’s inlet content and post-processing results.

Various “cryogenic” and “absorption” processing techniques beyond this Paper’s scope enable the plant to process the associated gas, thereby (a) extracting natural gas liquids (“NGLs”) for sale, (b) deriving residue gas for sale or field use, and (c) removing and handling inert gases.

After processing, the plant ships to a liquids hub – such as Mont Belvieu, Texas or Conway, Kansas – the gallons of NGLs extracted from the various associated gas streams entering the plant. Tailgate sales generate invoices showing gallons sold for each NGL product (*e.g.*, EP Mix, Propane, Pentane, Condensate (aka Natural Gasoline), and Raw Make), OPIS per-gallon prices for each product value, and transportation and fractionation per-gallon fees. Tailgate sales may include the methane residue gas extracted from the gas streams, sold to local utilities or pipelines; however, plant operations consume most residue gas or return the same to the field in order to enhance oil production (*i.e.*, generating field equipment, or injecting into the oil-producing reservoir for pressure maintenance or down wellbore annuluses for gas lifting).

The accounting for plant tailgate sales is fairly straightforward and transparent. However, the accounting further upstream – between wellhead production and plant processing – is very complex. Much of the complexity results from the unique nature of associated gas contracts, which are even lengthier and more thorough than gas well gas contracts. Associated gas contracts not only govern the title transfer and sales prices of associated gas, they govern also the substantial treatment and handling of gas inerts, as well as the use of plant products – such as residue gas, liquids, carbon dioxide and/or nitrogen – to enhance or facilitate oil production.

Associated gas contracts often contain “percentage of proceeds” price terms. Such terms will remit to the wellhead operator a percentage of the tailgate sales of liquids and residue gas, while enabling the plant to keep a percentage of the same as compensation for its processing and field services. In addition to “percentage of proceeds” price terms, plants may charge per-MCF or per-MMBTU for gathering and processing.

As a general rule: the older the contract, the greater the “percentage of proceeds” given to the plant (such as 50% or more). Also: the more affiliated wellhead operations are with plant ownership (*e.g.*, the wellhead operator and plant owner are the same company, or the wellhead operator owns 20% or more of the plant), the greater a percentage given to the plant.

Wellhead operators often lack other markets for their associated gas; few plants, if any, can take their associated gas. Also, wellhead operators’ oil production depends heavily on the processing and services provided by the plant. Consequently, contract

terms that favor heavily the plant to the detriment of the wellhead operator often occur even when the contract is not old and even when little to no affiliation exists between wellhead operations and plant ownership.

A trend in the past 10 years has been for gas plants (*i.e.*, buyers and processors) to protect themselves from “commodity price risk” – such as volatile NGL prices – by avoiding percentage-of-proceeds terms and using, instead, per-MCF processing fees. Such per-MCF fees protect wellhead operators (*i.e.*, sellers) from onerous proceeds terms. Contracts containing per-MCF fees effectively enable the wellhead operator to retain a very high percentage, such as 95% or more, of the value derived from NGLs and residue gas.

Following gathering, processing and tailgate sales, the wellhead operator must account to its royalty owners for royalties on NGLs and residue gas. Some operators allocate back to royalty decimals a share of NGL gallons and residue-gas MCFs. However, such operators lump together and do not distinguish among different types of NGLs (ethane vs. propane vs. pentanes+), which can vary considerably in per-gallon prices. Some operators convert NGL-value and residue gas-value to a combined per-MCF value and report to royalty owners solely in terms of MCFs.

Important documents will arise from the foregoing associated gas marketing: (i) production volume measurements; (ii) gathering-to-plant statements (showing the volume flow from point of production to plant inlet); (iii) plant settlement statements (showing plant’s sharing of proceeds with wellhead operators, usually on an “allocation basis”); (iv) maps and diagrams of gathering systems and post-plant tailgate transportation systems; (v) tariff invoices and payments thereof for post-plant tailgate systems; (vi) plant tailgate sales invoices; (vii) gas sales contracts between wellhead and plant; (viii) evidence of money sales; (ix) highly complex production-tax volume data; (x) royalty-decimal worksheets to allocate volumes to royalty owners; and (xi) pricing worksheets to calculate MCF prices or gallon prices on which royalties and production-taxes are paid. Most of these documents exist in electronic form only, such as Excel files or Access files derived from database programs. All such documents must be requested from the producer’s files in order to understand the associated gas marketing that has determined gas royalties. Also, engaging an associated-gas and/or plant-processing specialist is necessary in order to understand fully such documents.

Sample document requests, with definitions, the author has used in the past include:

*Contract files for the following leases/units feeding the Seminole Gas Processing Plant in Gaines County, Texas.*

*Contract files for the following leases/units in Gaines County: Seminole San Andres Unit (60475); “Riley” and “Seminole Deep” properties; GMK South; Hanford and East Hanford; various “Yates” properties or gathering systems; Adair Wolfcamp; Adair San Andres; “Young” properties; Big Run; Cedar Lake and MCRP; West*

*Seminole.*

*Simplified process-flow diagrams, accounting flow diagrams, plant balances, and plant allocation statements for the Seminole Gas Processing Plant, for January 1994 to present.*

*Monthly gas-analysis reports (chromatographs) for the various leases/units in Gaines County sending gas to the Seminole Gas Processing Plant: Seminole San Andres Unit (60475); "Riley" and "Seminole Deep" properties; GMK South; Hanford and East Hanford; various "Yates" properties or gathering systems; Adair Wolfcamp; Adair San Andres; "Young" properties; Big Run; Cedar Lake and MCRP; and West Seminole.*

....

*Any document in which you discussed or mentioned the percentage of proceeds on NGLs and residue gas to be remitted to the producer(s)/seller(s) in the associated gas contracts for the plant or for surrounding plants that send gas production through the plant.*

*Any document in which you discussed or mentioned changing or modifying the percentage of proceeds on NGLs and residue gas to be remitted to the producer(s)/seller(s) in the associated gas contracts for the plant or for surrounding plants that send gas production through the plant.*

....

*Current and accurate P&IDs (Piping and Instrumentation Diagrams), in effect during January 2002, September 2003, January 2004, May 2004, March 2005, March 2006, and January 2007.*

*P&IDs prepared in connection with PHAs (Process Hazard Analyses).*

*Simplified Process Flow Diagrams, in effect during January 2002, September 2003, January 2004, May 2004, March 2005, March 2006, and January 2007.*

*Accounting Flow Diagrams, or other documents similar to Simplified Process Flow Diagrams that have been modified to show meter locations, in effect during January 2002, September 2003, January 2004, May 2004, March 2005, March 2006, and January 2007.*

*Plant inlet meter reports for January 2002, September 2003, January 2004, May 2004, March 2005, March 2006, and January 2007.*

*Documents showing the field gas meters' sampling periods (e.g., quarterly, monthly, bi-monthly) and techniques (e.g., spot sampling, ratable sampling or continuous sampling).*

*Documents showing the plant inlet gas meters' sampling periods (e.g., quarterly, monthly, bi-monthly) and techniques (e.g., spot sampling, ratable sampling or continuous sampling).*

*Plant Allocation Statements and other documents showing how you allocate total gas volumes, including allocations of gas volumes to specific wells and/or well-by-well allocations.*

*Statements and reports generated during your last two Plant Balances, as well as documents showing the typical length of time between your Plant Balances.*

*For the gas plant, documents showing monthly calculations of the recoveries of ethane, propane, butane, iso-butane, pentane, any other natural gas liquids ("NGLs") and condensate from the casinghead gas streams flowing into the plant from 1994 to present.*

*For the gas plant, documents showing monthly sales of ethane, propane, butane, iso-butane, pentane, any other natural gas liquids ("NGLs"), condensate, and raw make from 1994 to present.*

*For the gas plant, the pricing worksheets for sales of ethane, propane, butane, iso-butane, pentane, any other natural gas liquids ("NGLs"), condensate, and raw make from 1994 to present.*

....

*Definitions:*

*"Purchasing and services contract" means gas-sales agreements, gas-handling agreements, gas-processing agreements, gas-settlement agreements, or similar agreements or contractual arrangements, including gas contracts on gas wells, whereby a gas gatherer or plant operator has handled or processed gas-well gas on behalf of lease/unit operators and/or working-interest owners, and whereby the gas gatherer or plant operator would remit to the various lease/unit operators and/or working-interest owners a "percentage of proceeds" price, price per MCF, or price per MMBTU for such production. When Purchasing and Services Contracts are requested, Defendant should produce also the contract briefs or contract summaries.*

*"Settlement Statement" means the monthly or periodic reports by the gas gatherer or plant operator showing the volume and quality of gas sent from a lease/unit to the gathering system or plant. Such Settlement Statements typically show the date of sampling, the sample meter number(s), chromatograph gas analyses, gas volumes, and contract terms (such as "percentage of proceeds" prices, per-MCF prices, or per-MMBTU prices). You have received these Settlement Statements in your capacity as gas producer or seller, working-interest owner in a lease/unit, or working interest owner in a*

*plant or gathering system.*

*“Contract File” means the correspondence and related agreements surrounding the formation, negotiation and execution of a purchasing and services contract, as well as the correspondence and related agreements relating to the performance of such contract. Information showing whether the producer/seller owned all or part of the processing plant/facility at the time of contract formation typically appears in the contract file.*

Inquiry into associated gas marketing, and related document requests, seek to learn whether the royalty owner is receiving a high, defensible percentage of value derived from the associated-gas stream, such as 80% or more of NGL and residue-gas sales. Also, the inquiry seeks to learn whether the royalty owner has any realistic ability to challenge the marketing arrangement governing the determination of such value. Associated gas marketing arrangements are complex and account for many factors affecting oil production and gas processing; they are not easily challenged or changed.

PROD T P	OWNER	UNIT		
DATE I C	INTEREST	PRICE	VOLUME	
Property:	8A-06003	Alex Slaughter		
0315 R O	0.00677083	44.13	5,197.43	
Property:	8A-06042	Frazier Unit		
0315 R O	0.00327968	44.38	637.15	
Property:	8A-067566	Texaco SEU		
0315 R O	0.00677083	44.20	7,160.65	
Property:	8A-181053	SEU		
0315 R O	0.00655935	44.13	83,968.66	

## Royalty Decimals

(and documents you'll need)

Notes: \_\_\_\_\_

\_\_\_\_\_

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Royalty-payment decimals will result from a mathematical analysis that begins with the underlying lease fraction, such as 1/4<sup>th</sup> equaling 0.25, or 1/8<sup>th</sup> equaling 0.125. Family inheritances or entity divisions of decimals, in a short time period or over decades, will diminish the actual decimal held by a royalty-underpayment claimant. For instance, a person whose grandparents held a full 0.125 royalty-decimal decimal in the 1930s may only have inherited 0.00045 of the original royalty interest.

Unitization and pooling will further diminish payment decimals. Whenever two or more leases are combined into a unit, or pooling unit, for purposes of conducting common operations for a certain area, the individual lease decimals become lower royalty-payment decimals. For instances, a person who held a 0.125 decimal in a lease may hold only a 0.00486 decimal in unit-wide production, if the underlying lease became a “unit tract” with a 3.89% “unit participation factor” – because 0.125 times 0.0389 equals 0.00486.

Division orders will memorialize a royalty-payment decimal, both for unitized leases and stand-alone leases. In Texas, division orders do not alter underlying lease language, such as royalty-valuation language. For instance, if a royalty owner is entitled to receive “market value” royalties, a division order cannot force him to accept “net proceeds at the wellhead” royalties. *See* TEX. NAT. RES. CODE § 91.402(h) (“The

execution of a division order between a royalty owner and lessee or between a royalty owner and a party other than lessee shall not change or relieve the lessee's specific, expressed or implied obligations under an oil and gas lease, including any obligation to market production as a reasonably prudent lessee. Any provision of a division order between payee and its lessee which is in contradiction with any provision of an oil and gas lease is invalid to the extent of the contradiction.”). However, until a royalty owner revokes it, a division order is binding *as to the decimal interest* on which the producer makes payments (*e.g.*, 0.125 controls over a competing higher decimal, such as 0.200). If a royalty owner is underpaid for a period of time during which a binding division order was in place, his remedy is not against the producer holding the binding division order, but rather against the over-paid royalty owner(s) – namely, those who inadvertently received royalties that ought to have gone to him. *See, e.g., Gavenda v. Strata Energy, Inc.*, 705 S.W.2d 690, 691-92 (Tex. 1986) (“The general rule in Texas, though, is that division and transfer orders bind underpaid royalty owners until revoked. . . . Generally, underpaid royalty owners, however, have a remedy: they can recover from the overpaid royalty owners.” (citations omitted)).

Royalty-owner claimants may not possess their entire royalty-underpayment claim. If a royalty owner purchased the royalty interest only a year before he pursues his underpayment claim, he may have standing to recover damages only for the previous year – and not for the full four-year preceding period typically allowed for underpayment claims. He must present evidence that he acquired all causes of action, including royalty-underpayment claims, when he acquired the underlying royalty interest. *See, e.g., John H. Carney & Assocs. v. Tex. Prop. & Cas. Ins. Guar. Ass'n*, 354 S.W.3d 843, 849-50 (Tex. App. – Austin 2011, pet. denied) (“[T]he general rule is that the right to sue for money damages is a chose in action, which is a property right that can be assigned unless assignment is prohibited by statute or is contrary to public policy.” (citations omitted)); *Castleman v. Redford*, 124 P.2d 293, 294-95 (Nev. 1942) (acknowledging and discussing the permissibility of express assignments of causes of action under Nevada law). The mere transfer of assets, such as real estate, from one party to another does not convey with those assets a related cause of action; rather, the assignor retains such causes of action unless he specifically conveys them. *E.g., Richey v. Stop N. Go Markets of Tx.*, 654 S.W.2d 430, 432 (1983) (“Because there was no express assignment here of his cause of action to [grantee], [grantor] retained his right to pursue the case following transfer of the property.”); *Smith v. Hamilton*, 265 P.2d 214, 215 (Nev. 1953) (citing with approval 52 C.J.S. 225 *Landlord and Tenant*, § 473(e): “An assignment of the lease by the tenant does not of itself . . . confer on the assignee the assignor's right to recover the deposit, and an assignee of the tenant claiming the deposit must show an assignment of the tenant's rights to such money.”). An acceptable assignment of cause of action, which can accompany the royalty-acquisition file or stand on its own, is as follows: