LOUISIANA INSTITUTE ON MINERAL LAW

Financial Market Implications On Implied Lease Obligations

By: David A. Barlow, Sklar Exploration Company L.L.C.

and

An Overview of Current Louisiana Law Regarding Such Issues

By: Leland G. Horton, Lemle & Kelleher, L.L.P.

Financial Market Implications On Implied Lease Obligations

By: David A. Barlow, Sklar Exploration Company L.L.C.

An Overview of Current Louisiana Law Regarding Such Issues
By: Leland G. Horton, Lemle & Kelleher, L.L.P.

I. The "Big Picture" As to Current Louisiana Law

II. Royalty Calculations Issues

- A. Dramatic Market Fluctuations Often Create Royalty Litigation
- B. Market Value Analysis and Common Themes in Royalty Litigation
- C. Royalty Litigation Over Costs Allocation

III. Allocation of Gathering and Transportation Costs

- A. Gathering Costs
- B. Transportation Costs to Downstream Markets

IV. Transactions Between Affiliated Entities

V. Louisiana Prescriptive Period for Royalty Claims

VI. Some Tentative Conclusions on Present Louisiana Law

Financial Market Implications On Implied Lease Obligations

Article 122 of the Louisiana Mineral Code implies in every mineral lease an obligation upon the mineral lessee to act as a reasonably prudent operator. La. R.S. 31:122. According to the legislative comments, this broad obligation includes the obligation to exercise reasonable diligence to secure a market for minerals that have been produced or are capable of being produced in paying quantities. The Legislature enacted the code effective as of January 1, 1975, when lessees marketed natural gas, the commodity on which this paper focuses, in a very different manner than today. The code itself grew out of the pre-existing jurisprudence that, in some cases, dates back to the early 1900's.

The Federal Power Commission ("FPC") regulated the maximum price of natural gas sold into interstate natural gas pipeline systems in 1975 when the Louisiana Mineral Code was enacted. At that time, it was acting pursuant to its authority under the Natural Gas Act of 1938, as interpreted by the U.S. Supreme Court decision in *Phillips* in 1954. The Federal Energy Regulatory Commission ("FERC") did not yet exist. In 1977, the Department of Energy Organization Act abolished FPC and created FERC. Initially, FERC regulated prices under the pricing provisions of the Natural Gas Policy Act of 1978. But changes in both statutory law and regulatory orders fundamentally altered the transportation and purchase and sale of natural gas in interstate pipelines in the United States. In 1985 and 1987, FERC issued Open Access Rule Orders 436 and 500, whose purpose was to encourage pipelines to offer open access, non-discriminatory transportation services so end users could contract directly with producers for gas supply. In 1989, Congress passed the Natural Gas Wellhead Decontrol Act allowing FERC regulation of producer sales of natural gas to be eliminated gradually until full decontrol in 1993. On April 9, 1992, FERC issued the Final Order 636, requiring pipelines to unbundle their sales services from their transportation services and to provide open access transportation service that is equal in quality for all gas supplies whether purchased from the pipeline or some other supplier. In a very short amount of time, Congress and FERC deregulated natural gas prices and unbundled the role of transporter and purchaser.

One result of the unbundling process is that the buyers of natural gas have changed. As a natural outgrowth of the process, the interstate pipelines withdrew from the traditional gas purchase or "merchant" function in the late-1990's, and divested of the related wellhead gathering functions which were no longer necessary for their longline transportation business. Independent and major gas producers assumed the role of gas purchaser, as well as various affiliated and independent marketing companies, which sold gas in the production area directly to the existing holders of pipeline transportation capacity: the local distributors, industrial consumers and retail marketing companies. Those new marketing entities, however, generally chose to purchase in bulk on mainline pipelines and at the tailgate of large processing plants. The primary market outlet for wellhead gathering and sales were left to the independent producer and newly created gathering companies, as the "first purchaser" of the commodity. Those entities had to perform the aggregation and marketing functions that used to be handled by interstate pipelines in the old bundled world.

With the fragmentation of the industry that ensued from the unbundling process, various financial instruments were soon developed to separate and reallocate various risks among the participants. As with other commodities such as wheat, corn, copper and pork bellies, functional fragmentation led to standardization of transportation and sales[1] contracts, which gave rise to common aggregation and pricing locations across the country and the emergence of index pricing and basis differentials. Today, producers are participants in a much more complex industry made up of the physical markets for natural gas, the financial markets for natural gas and the futures markets for natural gas.

Ironically, some of the trends in the downstream industry, and the infant midstream industry and markets to which it gave birth, are incongruous with trends in the upstream industry. At the same time transportation and sale contracts are being standardized, many lessors are adding riders to the old printed form mineral lease governing the relationship between lessor and lessee designed to transfer all of the risks and costs of operations downstream of the wellhead to the lessee and fundamentally change the meaning of a royalty and a lessee's duty to market. At the same time pipeline capacity is tight and quality specifications are vigorously enforced, higher prices for natural gas, combined with technological advancements in exploration, drilling, completion and stimulation, have producers drilling for deeper and generally poorer quality natural gas. At the same time that unregulated midstream companies begin to use their power to extract more revenue from producers, most producers are drilling wells in mature basins and generally finding fewer recoverable reserves and lower profits margins.

There are few Louisiana court cases interpreting the lessee's implied obligation to market, and the jurisprudence that does exist, like the code itself, largely predates the sea changes in the marketing of natural gas that have occurred over the last two decades. A lawyer advising a lessor or lessee in Louisiana has a body of statutory and jurisprudential authority from which to make arguments concerning a lessor's duty to market, but would have to limit opinion letters about many specific cases with the caveat that the law is not clear on the particular question at issue.

Businesses desire certainty and do not want to be the "guinea pigs." Producers lobby state legislatures in natural gas producing states to "fill in the gaps," and royalty owners respond with a sophisticated lobbying effort of their own. There is a rare convergence of lobbying efforts by the National Association of Royalty Owners ("NARO") and the Independent Petroleum Association of America ("IPAA") to regulate gathering and intrastate pipelines that may gain traction, but modifying the relationship of the lessor and lessee under the Louisiana Mineral Code is unlikely in Louisiana. The lessee's implied obligation to act as a reasonably prudent operator under the Louisiana Mineral Code, like any good statutory law in a civil law system, is a general principle of the law that is broad enough to be applied or extended by analogy to specific cases that its drafters could not have envisioned. In our opinion, the commentators, litigators and jurists of this state, not the Legislature, will clarify how the law applies to many specific cases. This paper explores how mineral lessees in Louisiana may use the physical, futures and financial markets for natural gas, as well as gathering issues that arise before the

[1] The North American Energy Standards Board ("NAESB") and the Gas Industry Standards Board "GISB" publish form Natural Gas Purchase And Sale Agreements that are commonly used by buyers and sellers of natural gas.

point of sale. Mr. Leland Horton's portion of this presentation puts those issues in the context of the statutory and jurisprudential authority governing the relationship between mineral lessor and lessee. We may raise more questions than answers and we advocate more of a case by case analysis than a bright line rule. But we believe that this is a fertile area of the law that deserves discussion and debate.

I. GATHERING AND TRANSPORTATION

A. GATHERING AND INTERCONNECTION

One basic reason that "market value" at the wellhead is difficult to ascertain is because the physical market for natural gas is generally not at the wellhead. Rather, mineral lessees typically sell natural gas downstream of the wellhead in pipelines or at hubs, a hub being a point where several pipelines or storage facilities connect. The wellhead may be located a long distance from any pipeline. Even a well located near a pipeline has no market unless it is connected to that pipeline and has capacity and a buyer on that line.

A simple example illustrates some of the obstacles a producer faces in getting its gas sold. Assume that a producer drills and completes a wildcat well. For the sake of simplicity, assume the well is drilled on a lease basis on lands covered by a single mineral lease owned by a single mineral lessor. To satisfy all of the LSU fans here, we will refer to this hypothetical producer/mineral lessee as "Tiger Production Co." or "Tiger" for short. The nearest pipeline to Tiger's well is a 30" interstate transmission line located approximately two miles from the wellsite. There are no existing taps on this transmission line in the vicinity of the well. In order to sell natural gas produced from the well, Tiger will have to lay a two-mile gathering line and pay to hot tap into the transmission line. The cost of the gathering line (pipe, right of way, labor) is $300,000, and the cost of the hot tap and related facilities is $200,000.

Tiger, or any other reasonably prudent operator, may or may not want to spend these capital costs to secure a market, depending on a number of variables, principally on the productive capabilities of the well. If the well is capable of being a prolific producer, then a reasonably prudent operator would spend these capital costs to get natural gas produced from it to a market and it is Tiger's duty to do so. However, what if the well will only be a marginal producer? What if the proceeds from the anticipated sale of natural gas from the well into that pipeline would be sufficient to cover operating costs, making the well technically capable of producing in paying quantities, but would not be sufficient to recoup the capital costs for the gathering line and tap? The answer is that a mineral lessee does not have a duty to spend capital costs to secure a market for minerals, even for a well capable of covering operating costs, if it does not have a reasonable expectation of recouping its capital costs. A more difficult issue arises if the proceeds from the anticipated sale of natural gas from the well into that pipeline would likely cover operating costs and recoup capital costs, but would not make much if any profit. Most mineral lessees would take the position that they do not have an obligation to swap dollars. They do not know on the front end the precise volume of recoverable natural gas reserves they expect to produce from the well or the commodity price they will receive for those reserves. They should bear no duty to spend capital costs to secure a market for minerals, even if capable of producing in paying quantities, unless they have a reasonable expectation of recovering those capital costs plus some profit commensurate with the risk that they are taking. Quantifying the risk is a more difficult matter.

A related issue is whether the mineral lessor bears a share of these capital costs to construct the gathering line and tap. The very definition of a royalty is a share of production free of the costs of production. But under a traditional "market value at the well" or "proceeds" royalty clause, royalty is valued at the well by working back from downstream sales. A mineral lessee accomplishes this valuation by deducting post production costs from the downstream sales price. The rationale is that costs subsequent to production generally increase the value of the product and must be "worked back" or "netted back" from the downstream sales price to obtain the true value at the well. Under this approach, a mineral lessee with a "market value at the well" or "proceeds" royalty clause may deduct the reasonable costs to transport the product from the well to a pipeline and to tap into that pipeline.[2]

There are various methods by which a mineral lessee deducts capital costs from its mineral lessor's royalty. If the capital costs were $500,000 and the well only makes $100,000 per month after severance taxes, then it would take five months to recover these costs if the mineral lessee deducted 100% of the royalty share of these capital costs from the lessor's royalty. During that period of time, the mineral lessor would receive no net royalty. More commonly, mineral lessees amortize these capital costs over a period of time, such as the shorter of the expected life of the equipment or well or field. In this example, if the well had a life expectancy of three years, then the mineral lessee may deduct from proceeds from the sale of natural gas attributable to the mineral lessor's royalty that owner's royalty share of $13,888.88 per month being the total amount amortized over 36 months. But if the well declines during that three-year period to generate less than $13,888.88 per month in gross revenue after severance taxes, then the mineral lessee again has the practical problem that the lessor is not receiving any royalties despite the good legal theory supporting its position. An alternative that avoids this pitfall is to charge a fee measured in cents per MCF. Thus, if the well had estimated recoverable reserves of 2 BCF of natural gas, then the mineral lessee may deduct 25 cents per MCF for a gathering charge ($500,000/2,000,000 MCF). Regardless of the approach used, the risk of amortizing over too long a period of time is borne by the lessee because he has no means of recovering costs out of the lessor's royalty if the well depletes or reaches its economic limit before the three-year or other amortization period is reached.

An aggressive mineral lessor may argue that having paid for its share of the capital costs to build the gathering line and tap into the transmission line, it now owns an interest in the equipment. The retort is that the mineral lessor never paid its share of these capital costs; instead, it was paid its royalty share. That royalty share, however, did not have a market value at the well and thus had to be valued by taking into account postproduction costs.

The legal relationship between the mineral lessor and mineral lessee can become more tenuous once the mineral lessee has recovered its capital costs to construct the gathering line and tap. An aggressive mineral lessee may continue deducting costs from its mineral lessor's royalty

---

[2] Whether Louisiana continues to follow this approach, as it did in *Compare Merritt v. Southwestern Elec. Power Co.*, 499 So. 2d 210 (La. App. 2d Cir. 1986), after the Supreme Court's decision in *Frey v. Amoco Production Company,* 603 So. 2d 166 (La. 1992), is discussed in more detail in Leland Horton's portion of this presentation.

on ground that the recovery of capital costs are not the issue. The issue is what is the mineral lessor entitled to, and the answer is that it is only entitled to be paid based on market value at the wellhead. If the gas is being sold downstream of the wellhead, then gathering fees must be worked back out of a downstream price to ascertain the true value at the wellhead. Some mineral lessees may even gather gas in the same gathering line from other leases for a fee. Pretty soon, the mineral lessee is profiting from its gathering line. Not only is it profiting from that gathering line, but it owns many other gathering lines from which it is also generating revenue. The mineral lessee decides that if it sells those gathering assets to an affiliated company that is not subject to any mineral leases. Mineral lessors knee jerk response is often to add pages and pages of riders to their mineral lease prohibiting companies affiliated with the lessee from gathering or marketing natural gas produced from the well which, for reasons discussed below, may not be in their best interest either.

B. QUALITY SPECIFICATIONS

Another reason that "market value" at the well is difficult to ascertain is because gas produced at the wellhead is often not of marketable quality. Assume, for instance, that Tiger has laid the gathering line and tapped into the transmission line. Tiger now has secured a market, right? Maybe. Maybe not. Most Interconnect Agreements with interstate pipelines contain language that provides as follows:

> "Interconnecting Party agrees to deliver gas in accordance with the Pipeline's FERC Gas Tariff. Pipeline's FERC Gas Tariff gas specifications as currently effective are attached as Exhibit "A." Pipeline reserves the right to refuse to accept totally, or in part, gas not fully in compliance with the GQ&M Sections and/or not interchangeable with Pipeline's standard gas composition."
>
> "The gas delivered by Interconnecting Party at the Interconnect Point shall be at the varying pressures that exist in Pipeline's line from time to time, but in no event in excess of Pipeline's maximum allowable operating pressure. Interconnecting Party agrees that in the event compression is required or pressure reducing equipment is required to facilitate delivery by Interconnecting Party into Pipeline's line, Interconnecting Party shall be responsible, at its expense, to install, own, operate, and maintain such facilities."

In this case, assume that the natural gas produced from the well is not entirely made up of methane and that its quality does not conform to the quality specifications under the pipeline company's tariff in three ways: (1) CO_2 exceeds the limit; (2) water saturation exceeds the limit; and (3) hydrocarbon dewpoint exceeds the limit. In order to deliver natural gas produced from the well into the transmission line, the producer must purchase or lease an amine unit to bring the CO_2 into spec, a dehydration unit to extract H_2O from the natural gas and a JT Plant or Refrigeration Plant to knock out natural gas liquids from the natural gas. Let's further assume that the operating pressure on the transmission line is 950 psi, and the pressure of natural gas at the outlet of the JT Plant is low. So the producer must also purchase or lease a compressor to compress the natural gas to pipeline pressure. In some cases, the wellhead pressure is so low that produced gas must be compressed both before and after treating and processing.

The same issue discussed above arises concerning whether the mineral lessee may deduct any of these postproduction costs from the mineral lessor's royalty. But assume that the mineral lease in question contains a "market value at the well" royalty clause together with a rider providing the mineral lessee shall not deduct postproduction costs from the value of the lessor's royalty. One approach to this dilemma is the path followed in *Heritage Resources, Inc. v. NationsBank*, 939 S.W.2d 118 (Tex. 1996). In that case, the Texas Supreme Court held that the "no deductions" language is "surplusage as a matter of law" because one cannot determine the market value at the well when the point of sale is downstream without using the work-back method.

Assume here that Tiger is unsure whether a Louisiana court would follow the *Heritage Resources, Inc*. case, and decides that if it cannot pass a share of these costs on to its mineral lessor, then it is not going to sell its gas at the pipeline. Rather, it will enter into a contract with a midstream company that buys the gas at the wellhead. The midstream company will spend all of the capital costs to tap into the line, lay the gathering line to the well, and install surface production equipment to make the wellhead gas of sufficient quality and pressure to deliver into the transmission line. The midstream company offers a price for the gas at the wellhead based on an index price less a certain number of dollars per mmBtu. The price approximates what the lessee would have obtained had he sold the gas at the same delivery point in the transmission line, less his expected fuel loss and consumption and gathering, treating, dehydrating, processing and compression costs, and less a profit margin that the midstream company builds into the deal for itself commensurate with the costs and risks it bears. Further, the midstream company requires the lessee to furnish financial guarantees in the form of a dedication of reserves and a $500,000 letter of credit securing the principal obligation to deliver the reserves. The lessee solicits and obtains bids from various third party midstream companies to purchase the gas at the wellhead in this manner and chooses the best bid.

Now there is no need to work back because the natural gas is being sold at the price that third parties are ready, willing and able to pay at the well. The mineral lessor and mineral lessee both get the market value at the wellhead.

Assume a slightly different factual scenario. In particular, assume that Tiger Production Co. solicits the bids from the third party midstream companies, but instead of awarding them the job, it awards the job to his own affiliated company, Tiger Marketing Co., on the same terms and conditions. The mere fact that Tiger Marketing is affiliated with Tiger Production does not make the transaction a sham. Indeed, the transaction appears to be arm's length in that Tiger Marketing is merely performing under terms and conditions that Tiger Production negotiated with third parties. Regardless, as discussed below with regard to marketing affiliates in the physical sales context, mineral lessors will, as a practical matter, apply a microscope to a transaction in which an affiliate is involved to a much greater degree than a third party.

C. TRANSPORTATION AGREEMENTS

1. Capacity Limitations

Let's go back to our original scenario. Assume that Tiger's mineral lease contains a "market value at the well" royalty clause and it does not contain a "no deductions" rider. Tiger decides to gather, treat, dehydrate, compress and extract natural gas liquids from the wellhead gas on its own and not use a third party or affiliated company. Tiger enters into an Interconnect Agreement with the pipeline company to tap into the 30" transmission line. Once the gas has been gathered to the interconnect point, made to conform to quality specifications and is at the pipeline's operating pressure, Tiger has finally secured a market, right? Again the answer is maybe or maybe not. Most Interconnect Agreements with interstate pipelines contain language as follows reminding the mineral lessee that taping into the pipeline does not necessarily constitute securing a market:

> "Availability of capacity and capacity allocations on Pipeline's system are governed by the terms and conditions of its FERC Gas Tariff and Service Agreements authorized thereunder. By this Agreement Pipeline is not assuring or guaranteeing that capacity shall be available in its transmission system to transport gas from Interconnecting Party's Interconnect Point."

* * *

> "Notwithstanding anything to the contrary contained herein, it is fully understood by Interconnecting Party that Pipeline's Transportation Agreement must first be entered into between Pipeline and Interconnecting Party and gas nominated thereunder, or gas must be nominated under a Transportation Agreement between Pipeline and a third party before any gas may be received or delivered to the Interconnect Point."

A combination of the emergence of new sources of supply, such as the Bossier and Barnett shale trends in East Texas, and a decade or more of limited investment in pipeline infrastructure has created capacity problems in some areas for producers. The importation of liquefied natural gas or LNG's to the Louisiana gulf coast may exacerbate the problem both from a volume and quality perspective. Many pipeline companies have announced or are actually implementing expansion projects ranging from increasing capacity on existing lines, system extensions, construction of laterals from existing systems, conversion of oil pipelines to natural gas pipelines or construction of entirely new natural gas pipeline systems. In the meantime, it is not unheard of for a producer without firm transportation capacity to be shut in or curtailed from time to time.

Does the mineral lessee's obligation to exercise reasonable diligence to secure a market for natural gas include an obligation to obtain firm transportation capacity? In practice, many mineral lessees, particularly small independents, will not actually transport natural gas downstream of the interconnect point. Instead, they will enter into a purchase and sale agreement with a shipper that has an existing Transportation Agreement with firm or interruptible capacity on that line with the point of delivery being the interconnect point where the mineral lessee's gathering line intersects and taps into the pipeline company's transmission line. Alternatively, the mineral lessee may enter into an agency agreement with a marketing company that pools natural gas from that producer and others on that pipeline, transports the collective gas downstream under a Transportation Agreement with the pipeline company (spreading the financial risks that a firm Transportation Agreement introduces) and sells it on their behalf to end users or other buyers. A more sophisticated seller may sometimes sell at the interconnect point and sometimes downstream, or may sell some volume at each point during the same time period, depending on capacity, basis and other variables.

In any event, regardless of how the mineral lessee actually markets its natural gas, there is again a cost to securing a market. If the mineral lessee actually enters into a Transportation Agreement with the pipeline company, then the payment will take the form of a reservation charge to reserve capacity on that line and a transportation fee to transport the gas from the interconnect point to its point of sale downstream, among other costs. On the other hand, if the mineral lessee sells its gas to a shipper on that line, then that shipper is paying those same charges and fees to the pipeline company and will certainly pass them on, and then some, to the mineral lessee. And, of course, those agents that pool natural gas on behalf of producers do not work for free. In the words of a wise Bankruptcy Court judge in the Western District of Louisiana, "you've got to pay to play." However, as discussed below with respect to the physical sales of natural gas in the spot market, there is often more value downstream than at the interconnect point.

2. Other Issues Before The Point Of Sale

It can be questionable whether other costs associated with marketing natural gas before the point of sale are deductible from the mineral lessor's royalty. For instance, who bears the loss of natural gas that is consumed as fuel depends on both the type of lease at issue and under what circumstances the gas is consumed. Many Bath forms and other mineral leases commonly used in Louisiana allow the mineral lessee to consume natural gas free of any royalty obligation as fuel in connection with production facilities on the leased premises or lands pooled therewith. More sophisticated leases, in contrast, require payment of royalties of all gas produced and saved or "utilized." Thus, in our hypothetical example, if Tiger set up its compressor on the leased premises and used wellhead natural gas to fuel the compressor, then under most leases Tiger would not have to pay royalty on the portion of the natural gas produced from the well that it used to fuel the compressor. It may use that natural gas as fuel free of any royalty obligation. If, on the other hand, Tiger compressed natural gas at the interconnect point two miles from the well site, then Tiger would have to pay royalty on the portion of the natural gas consumed. However, even if it owes royalty on natural gas consumed as fuel off the leased premises, Tiger could still argue that the costs of that fuel could be worked back out of the price. In other words, Tiger loses the argument on volume, but wins it on price. Tiger would pay the mineral lessor for the total volume produced from the well, including natural gas consumed as fuel off premises, but it would pay the mineral lessor the price after deducting the cost of that fuel.

It is not just Tiger who may consume natural gas as fuel off the leased premises. Most Transportation Agreements provide that the shipper must reimburse the pipeline company for the quantity of gas required for fuel, company use and unaccounted for associated with the transportation service thereunder in accordance with the pipeline company's tariff. The analysis here is the same as if Tiger is consuming the fuel. Tiger should pay the royalty owner based on the volume produced from the wellhead but, in calculating the price paid, may deduct the fuel retained as a postproduction cost that enhances the value of the product.

Closely related to the issue of consumption is that of loss. Most Interconnect Agreements provide in this regard that "[i]n the event of a line loss or leak upstream of the Interconnect Point, Interconnecting Party shall be responsible and liable for the gas loss." Line loss is like faith in God. You know that it is real, but it is hard to convince someone who is skeptical by nature. Mineral lessors are skeptical by nature. If they cannot remember the days of "hot oil" themselves, their grandfathers told them about it. Consequently, if volume is 3000 MCF at the wellhead, but 2700 MCF at the downstream sales point, they instinctively think that somebody is stealing the 10% that is lost on the way to market.

Another loss that sometimes confounds royalty owners is the loss that occurs in the treatment process itself. If the natural gas contains CO_2 in concentrations of 6%, and the pipeline company's quality specification requires that CO_2 not exceed 1%, then the volume of natural gas at the outlet of the amine unit should be at least 5% less than the volume at the inlet of the amine unit as a result of the treating process independent of fuel consumption and line loss. If the CO_2 or other byproducts that are extracted in the treating process is worthless, then the mineral lessor cannot complain if it is being paid based on the volume of gas at the outlet of the amine unit.[3] On the other hand, if natural gas liquids are being extracted, then as discussed below, the rights and obligations between the mineral lessor and lessee can be more complicated.

Nominations with pipeline companies can give rise to other costs before the point of sale. In particular, most Transportation Agreements require the shipper to nominate the volumes of gas that it intends to transport between points of delivery/receipt on the pipeline. Imbalance charges can arise if the shipper fails to deliver the nominated quantity. Or if the shipper delivers more quantity than it nominated, many pipelines reserve the right to charge an overrun fee or penalty or even to vent excess natural gas.

D. LIMITATIONS ON COSTS BEFORE THE POINT OF SALE

There are arguably more points of contention between mineral lessors and lessees prior to the point of sale in the area of gathering and transportation than at the point of sale in the physical, financial and futures markets. But royalty owners and producers would do well to recognize their common interests with regard to gathering and transportation. Mineral lessors do not always improve their situation by littering the mineral lease with riders that try to shift all of

[3] CO_2 in small quantities is a nuisance but CO_2, Nitrogen and Helium can have significant value when they are found in large quantities. Helium, for instance, sells at a much higher price than methane, often $50 per MCF or more. Ironically, many operators will purchase CO_2 to energize their fracture stimulation of a natural gas producing sandstone, only to turn around and pay to extract C02 from natural gas produced from the well in order to bring it into quality specifications.

the postproduction costs and risks to their lessees. Under the current industry structure, very few independent marketing companies purchase gas at the wellhead. In addition, few fields can support economically two gathering systems, absent a major new discovery. Accordingly, the producers often represent the only competitive alternative to the independent gatherers for gathering and marketing services. If a producer's marketing and gathering investment decisions carry too much risk of uncertainty regarding royalties, then royalty owners will be unwittingly driving producers away from that risk and toward the use of third party gatherers for wellhead sales and gathering services. As illustrated in the Tiger Production Co. example above, mineral lessees can skillfully maneuver around such obstacles by selling gas at the wellhead to a third party gathering company. But are the parties better off? Although it has worked around the "no deductions" clause in the mineral lease, Tiger has had to put up financial guarantees and may also have to dedicate its acreage. The mineral lessor is getting the market value at the well, for which it bargained, but it is effectively paying postproduction costs which it thought it would not bear.

The long-term consequences are more severe. The producer now has fewer available options in getting its gas to market, and both the producer and royalty owner will have to accept a lower netback wellhead price for the commodity. Furthermore, both may realize lower prices because of fewer buyers at "pooling points" exiting a gathering system as well as more balancing and penalty costs under a third party gathering service. The costs, of course, become magnified because the gatherer, with its installed facilities, gains market power after a field moves into development and again as the field begins to decline. The legal relationship between lessor and lessee does not limit what the gatherer can charge in fees or pay for natural gas. Instead, its limits are more practical, and essentially depend on the alternative markets. If there are no feasible ones, particularly toward the end of the well's or field's productive life, then it will increase its cut. After all, its only interest is making a profit from the transaction. In short, the lessor is exposed to risks in this scenario from which it would otherwise be protected due to the common interest of the lessor and lessee and the existing law governing their relationship protecting the lessor.

Mineral lessees, for their part, need to realize that they, unlike third party gatherers, are limited by Article 122 of the Louisiana Mineral Code if not the terms of the lease itself. I often hear producers complain about how tough the state lease form is, but the following text from the state form, in contrast to many leases that are entirely one-sided, strikes a *via media*:

> "If Lessee delivers such gas at a point outside the field in which this lease is situated, Lessee may deduct from the value of such gas a reasonable sum for transportation from the field to the point of delivery by means of facilities belonging to an independent party, not in excess of actual cost. If such transportation is by means of facilities owned by one other than an independent party, Lessee may deduct the actual cost of such transportation, but only if such cost is no greater than the fair value of the services performed; if actual cost is greater than fair value, the fair value shall determine the amount to be deducted. If such transportation is by means of any facilities owned by Lessee, Lessee may deduct from the value of production a reasonable sum for such services, computed as follows: the amount deductible shall include only (1) the direct cost of

> operation and maintenance, including cost of labor, direct supervision, fuel, supplies, ordinary repairs, and ad valorem taxes; and (2) depreciation of the facility computed over the estimated life of the field."

Whether this language is included in the lease, is not some limitation implied in law? Stated differently, would not a court analyzing whether a mineral lessee has properly deducted post production costs from the mineral lessor's royalty under Article 122 inquire whether those costs were actual, whether they were reasonable and whether they constitute a fair value of the services performed?

If the enemy of my enemy is my friend, then royalty owners and producers may actually unify over this issue. After all, post production costs are a source of conflict when it is the mineral lessee that is deducting gathering and other fees from the mineral lessor's royalty, but they are a source of unity when an unregulated, third party intrastate gathering company charges both mineral lessor and mineral lessee such fees for their services. NARO President Linn A. Willers summarized the opinion of royalty owners on the subject provides as follows:

> "We must take action, now, to help preserve the integrity of natural gas production, or the marketing system could be facing a meltdown in the coming months and years. The proliferation of Master Limited Partnerships which creates virtual regional monopolies in the pipeline-gathering sector, coupled with relatively ineffective or non-existent intrastate regulatory oversight, has resulted in enormous profits for a handful of companies at the expense of independent producers without pipeline capabilities, royalty interest owners and consumers of natural gas and its by-products. It is essential to the health of our industry that NARO does its best to support a competitive natural gas market and transparency in the area of contractual transportation agreements."

Producers are waging the fight at FERC with regard to both onshore and offshore gathering facilities. In comments submitted to FERC regarding reassertion of jurisdiction over the gathering services of natural gas company affiliates, the IPAA argued on behalf of producers as follows with regard to onshore gathering:

> "Unlike other commodities, it is not practical to move natural gas from domestic wells to mainline transmission lines in any manner other than through smaller diameter gathering lines. In the absence of either federal or state regulation or other form of oversight, domestic producers are held hostage to whatever rates the gathering company wishes to charge. On the one hand, the price of the natural gas commodity is set by the marketplace. On the other hand, the mainline interstate transportation rates are set by the Commission in recognition of the pipeline's monopoly power and the need to protect consumers from the exercise of this monopoly power. However, absent similar state regulatory protection, producers are caught in the middle with no way to guarantee that they can recover these gathering costs in the commodity sales price."

Absent federal legislation, FERC will likely not regulate onshore or offshore gathering facilities because it lacks jurisdiction. See, e.g., *Jupiter Energy Corp. v. FERC*, No. 05-61173, slip op. at 10 (5th Cir. Mar. 15 2007)(holding that FERC must articulate reasons for dismissing the import of non-jurisdictional physical factors and relevant non-physical factors in determining whether two natural gas pipelines located approximately ten miles offshore from Louisiana gather as opposed to transport natural gas).

In recent comments on the subject, Commission Chairman Joseph T. Kelliher stated as follows:

> "The Commission has tried a number of times to assert jurisdiction over offshore gathering facilities to protect against undue preference and the exercise of monopoly power, but has been repeatedly rebuffed by the courts. We must accept the judgment of the courts. Under current law, offshore gathering is an unregulated monopoly. That will remain the case unless and until the law changes."

Even if Congress wanted to change the law, its own power is limited by the Constitution to interstate commerce. If policy changes are effected legislatively, it is more likely that they occur at the state level where one would think that the combined efforts of royalty owners and producers would be formidable.

II. THE FINANCIAL MARKETS

A. SPOT MARKET

1. Natural Gas Purchase And Sale Agreements

Most producers in Louisiana sell their natural gas production in the spot market. A spot market in general is a market in which payment or delivery is immediate. Black's Law Dictionary 984 (7 ed. 1999). In the natural gas context, it is sometimes called the "physical" or "cash" market.

The purchase and sale of natural gas, like the transportation of natural gas, can be either on a firm or interruptible basis. Most purchase and sale contracts allow for a combination of firm and interruptible sales. Neither party may unilaterally interrupt its delivery or receipt of volumes purchased and sold on a firm basis except as a result of an event of force majeure. Volumes delivered on an interruptible basis, which are often called "swing" volumes, are generally defined as those volumes exceeding firm volumes. Although either party may freely interrupt its performance for swing volumes that party may still be subject to nomination and imbalance obligations under the purchase and sale agreement. Indeed, for both swing and firm volumes, the seller generally bears imbalance charges arising out of its failure to deliver nominated volumes until the buyer and transporter confirm changes in deliveries.

The NAESB and GISB forms are commonly used by buyers and sellers alike to sell natural gas. The term of a natural gas purchase and sale agreement can be and generally is longer than one month. However, each transaction under that agreement is generally for a term of one month. Although the daily cash market for natural gas is active, the majority of gas trading for a given month occurs during the last week of the preceding month. This period of time is known in the industry as "bid week." It is the last five business days of each month when producers generally sell all of their available volumes of natural gas for the following month in concert with the pipeline's requirements that all nominations for gas transportation be made at least three business days prior to the first of a given month.

2. Pricing

The price of natural gas is no longer regulated. Instead, it is dictated by what a buyer is ready, willing and able to pay and a seller is ready, willing and able to accept in the marketplace. Like other commodities, natural gas prices in the United States are influenced by supply and demand. The factors affecting supply include domestic production, imports of dry gas from Mexico and Canada and imports of LNG from overseas and storage facilities. The weather and the economy, above all other factors, influence demand. The price of other commodities, such as crude oil and coal, also influence demand, as many industrial and utility consumers can change their source of fuel to use the cheapest fuel in the existing marketplace.

In our hypothetical, Tiger's cash market is either at the well, if it sells to the midstream company, or at the interconnect point where its gathering line interconnects and taps into the pipeline company's transmission line or some other point of sale downstream from that interconnect point. It may be theoretically possible for a mineral lessee in Louisiana to transport natural gas produced here all the way to Transco Zone 6 in New Jersey for distribution to New York, but it is not feasible. Accordingly, prices in general can be analyzed with reference to supply and demand on a national basis, but index prices at a particular hub are also greatly influenced by local or regional supply and demand factors.

Thus, one of the main factors affecting price is the location of the delivery point. Prices are generally based on an index. Index prices are intended to represent an average price of natural gas delivered to a hub or other specific point on a pipeline at or during a specific period of time. Henry Hub, a place near Erath, Louisiana where 13 major pipelines (including Gulf South Pipeline, Southern Natural Gas, Natural Gas Pipeline Co. of America, Texas Gas Transmission, Sabine Pipe Line, Columbia Gulf Transmission, Transcontinental Gas Pipe Line, Trunkline Gas, Jefferson Island Pipeline and Acadian Gas) have receipt/delivery points, is one of the most common indexes used for physical sales of natural gas in Louisiana and, as discussed below, is also the delivery point for most natural gas futures contracts in North America.[4]

The term "basis" is sometimes used to describe the difference between the price of natural gas at different delivery points. It is also used to describe the difference between the price of natural gas at different times, such as the cash price less the future price.

The method of how index prices are collected, calculated and reported is controversial. Platts, a division of the McGraw-Hill Companies, is the publisher of Gas Daily and Inside FERC's Gas Market Report. It collects detailed, transaction-level data from actual buyers and sellers. For the daily price survey published in Gas Daily, market participants must report each business day all fixed-price physical deals completed prior to the NAESB nomination deadline for the next-day delivery in North America. For the monthly bidweek price survey published in Inside FERC's Gas Market Report, market participants report all fixed-price physical deals negotiated during bidweek for delivery throughout the next month. All transactions are listed individually and must specify delivery point, price, volume, source, buy/sell indicator, trade date, start flow date, end flow date, counterparty name and intermediary name (broker or trading platform).

Pricing can also vary based on whether the volumes are sold on a firm or interruptible basis. Firm volumes are generally based on prices prior to the month of delivery. For instance, under a "trigger" firm contract, the Seller notifies the Buyer of its desire to sell a certain quantity of natural gas for a certain time period, generally the next month, at a certain execution price less a certain basis differential, and the Buyer attempts to lock in those terms for that period of time by entering into offsetting transactions in the marketplace. Under a "baseload" firm contract, the Seller designates a firm baseload volume for the next month to be priced at the Inside FERC's Gas Market Report first of the month Index for the appropriate month of delivery under the heading Market Center Spot Gas Prices, less a fixed basis differential. Swing volumes, in contrast, are priced at either the daily price for the day in which the gas is delivered or the arithmetic average of all the daily prices for the given month in which the gas is delivered, less a fixed basis differential. In a purchase and sale agreement with tiered pricing for firm and interruptible volumes, the first gas through the meter is deemed the triggered firm volumes, subsequent deliveries are deemed to be baseload firm volumes and all other deliveries are deemed interruptible or swing volumes.

[4] As a matter of historical interest with legal implications, Henry Hub was shut-in between approximately September 23, 2005 and October 4, 2005 as a result of Hurricane Rita. Physical deliveries and receipts at that delivery point ceased. Purchasers and sellers whose contracts were tied to the Henry Hub index looked for an alternative index price or basket of indices to replace their agreed upon index price. NYMEX declared an event of force majeure on September 23, 2005 for both September and October 2005 natural gas futures contract delivery obligations. For a brief but important period of time, Hurricane Rita inflicted its damage to natural gas markets, removing both a key trading center and national benchmark for prices.

3. First Of The Month Versus Daily Price

The exact price owed a mineral lessor and the extent to which the mineral lessee is obligated to get the best possible price can be complicated even in the cash market. Additional facts about Tiger, our hypothetical mineral lessee, illustrate some of the issues. Assume that Tiger sells natural gas, either baseloading or swinging volumes, to a third party buyer at the interconnect point based on an index price less a basis differential. Assume further that Tiger had an extraordinary year in picking whether to baseload or swing monthly volumes. In those months when the first of the month price exceeded the daily price or average daily price, Tiger sold all of its volume on a baseload basis, whereas in those months when the daily price or average daily price exceeded the first of the month price, Tiger sold all of its volume on a swing basis. Assume further for the sake of convenience that Tiger produced exactly 100,000 mmBtu per month or 1.2 BCF (assuming 1000 btu/cf) for the entire 12 month time period of 2006 attributable to this single mineral lease. The difference between the first of the month price and the daily average price for Henry Hub varies but is almost always material. The smallest difference during 2006 was 15 cents per mmBtu, whereas the largest difference was $2.69 per mmBtu. Before severance tax and royalty, Tiger would have grossed over $1.1 million more during 2006 due to its extraordinary skill or luck marketing natural gas produced from one lease by picking either the first of the month price or the daily average price.

If the lessor's royalty under the mineral lease is 25%, is the royalty owner entitled to his 25% share of that profit? The volume and quality of the natural gas delivered has not changed. The delivery point is the same. The index used for pricing is even the same. The only difference was that the mineral lessee was extraordinarily good at choosing whether to baseload or swing volumes sold in the cash market, and the difference between first of the month and daily price even using the same index can be dramatic.

From the lessee's perspective, the question centers upon whether the lessor is bearing the same risk that the lessee bears. Changing the facts illustrate the point. Now assume that Tiger is extraordinarily poor at picking whether to baseload or swing. Instead of always picking the more profitable choice, Tiger always picks the wrong choice for the same time period. Thus, Tiger grosses $1.1 million less than it could have because of its poor choices. Has the mineral lessee breached its obligation to get the best price obtainable by reasonable efforts? Does Tiger owe the mineral lessor the best price it could have obtained had it picked correctly? If so, then it is heads the lessor wins and tails the lessee loses. It is obviously impossible for any lessee to pick correctly all of the time.

Most lessors are hindered by a lack of information. They do not subscribe to Gas Daily or Inside FERC's Gas Market Report and they are not privy to the transactions into which their lessee is entering. But that does not stop them from making the most out of the information that they do have. A favorite technique is to compare checks from different operators in the same field. If one check for natural gas produced from the field during January of 2006 is for a price close to $11.45/mmBtu and another is for a price close to $8.76/mmBtu, then the mineral lessor will assume the operator who paid the lower amount is taking advantage when, in fact, they both represent "market" prices for the preferred Henry Hub index during that period of time.

4. Performing With Spot Gas Purchases

One way for the mineral lessee to exploit the differences between first of the month and daily prices is to de-link the purchase and sale contract from physical deliveries from this well. A modification of the assumed facts with regard to our hypothetical mineral lessee, Tiger Production Co., shows how this can be done. Assume that Tiger calls its natural gas purchaser and baseloads 100,000 mmBtus attributable to the lease in question for the month of January 2006 at a price of Henry Hub first of the month index price less 25 cents or $11.20/mmBtu. After locking in this first of the month price, however, Tiger's well is shut-in due to mechanical difficulties. In order to perform under its purchase and sale contract, Tiger decides to buy natural gas on the spot market and deliver that gas to its purchaser. Tiger pays approximately $8.51/mmBtu to buy natural gas at this location using the average daily index price less the same basis differential, but it sells the gas at a price of $11.20/mmBtu. Thus, Tiger nets $2.69 per mmBtu multiplied by 100,000 mmBtu's or $269,000.

Tiger would obviously argue that it does not owe its mineral lessee any royalty on its profit from trading activities because it did not actually sell any natural gas produced attributable to the lease.

But a small change in the assumed facts calls Tiger's argument into question. Assume that instead of shutting in the well because of mechanical difficulties, Tiger shut in the well simply to profit from the spread between the first of the month and daily prices without having to produce its well and without having to share any of the proceeds with royalty owners or severance tax authorities. As a result, the royalty owner missed out on one of the highest priced months in recent history. Now has Tiger breached its implied obligation to exercise reasonable diligence to secure a market for its mineral lessee?

Change only one fact in the hypothetical – the month of delivery - and Tiger's position does not look so enviable. Assume that Tiger, like any good gambler, decides that it has the knack for making money marking. At the end of September 2006, Tiger decides to baseload 100,000 mmBtus for delivery in October 2006 attributable to the mineral lease in question at the same price of Henry Hub first of the month index price less 25 cents. Tiger has to shut in its well again due to mechanical difficulties. However, the difference between the first of the month and the daily index price works against Tiger this month. Now, Tiger has to purchase natural gas on the spot market at a price of $5.40/mmBtu to deliver to its purchaser under its natural gas purchase and sale agreement for which it only receives $3.95/mmBtu. Tiger has lost $145,000 on gas marketing without even producing any gas. Producers who do not have other means of making up for unforeseen events are generally quite cautious in selling firm volumes for this reason: The market can work against you.

A long-term purchase and sale contract containing a fixed price with an end user, such as a distribution company, electric utility or industrial consumer, can give rise to these same issues between mineral lessor and mineral lessee. The dollars involved, however, can become more significant since both the volume of natural gas at issue and the variances between fixed prices and floating prices become more pronounced over numerous months.

5. Price At Interconnect Point Versus Downstream Price

Significant variations in price can also occur depending on where the delivery point is for the sale. A modification of our hypothetical dealing with Tiger Production Co. illustrates the questions such variations can create in the relationship between the mineral lessor and lessee. Assume that the interstate transmission line in which Tiger is delivering natural gas connects two hubs each of which has its own published index price. For simplicity, call these two fictitious hubs and index prices East Tx and West Ms. The average basis, or difference of price between these two hubs, is about 20 cents per mmBtu with the West Ms being generally the preferred market. Assume Tiger taps into the transmission line in the Western part of North Louisiana. If Tiger sells its gas at that interconnect point, its contract price is East Tx index price less 10 cents per mmBtu. If Tiger sells its gas downstream at the West Ms hub, it gets West Ms less 10 cents, but it pays 20 cents in transportation fees. Thus, during normal time periods, Tiger has no incentive to do anything other than sell at the interconnect point. However, during particular times of the year, the basis between the two hubs can increase to $1.00. During those periods of time, when the pipeline has excess capacity, Tiger transports its gas down the line for the 20 cent fee, sells it downstream of the interconnect point at the West Ms hub and obtains a net price that is 80 cents higher. What does Tiger owe the mineral lessor? Stated differently, how far downstream does a mineral lessor's royalty extend?

6. Marketing Fees And Affiliated Marketing Companies

The affiliated marketing company, like the midstream MLP, is a feared and loathed bogeyman of mineral lessors. Like it or not, both entities provide a valuable role in today's unregulated marketplace. However, as soon as some of the legitimate marketing techniques discussed herein are employed by the mineral lessee's marketing affiliate instead of a third party or the mineral lessee itself, the transaction is suddenly clouded by suspicion.

Consider the following example. Assume that our mineral lessee, Tiger Production Co., is not good at marketing. Tiger's president has a good friend, though, who specializes in marketing natural gas. The friend charges a 2.5% marketing fee. The friend gets the same price that Tiger would get on its own if it marketed its own production. Tiger rationalizes that the 2.5% marketing fee is less than the overhead it would have to spend to establish a marketing department or affiliate and, in any event, Tiger's president likes helping out his friend. There are some other intangible benefits to using the marketing company. It sponsors an expense paid trip for its customers every year to Augusta National to see the Masters.

In this light, Tiger is going to have a hard time justifying the 2.5% marketing fee to its mineral lessor.[5] But consider a few more intangibles. The marketing company is very good at

[5] Many small non-operating working interest owners do not have enough volume to justify taking their share of production in kind and marketing it themselves, but are faced with the dilemma of signing a horribly one-sided marketing agreement that includes a marketing fee for or be underbalanced under a gas balancing agreement. They

"customer service." This not only includes trips and dinners and gifts, but also flexibility with delivery obligations. Those months when Tiger has problems with its well and cannot meet its nominations and firm delivery obligations, the marketing company does not charge imbalance fees or require delivery. It makes up the shortage from other supplies at no cost to Tiger. That would have come in handy during our hypothetical above when Tiger baseloaded all of its production for the month of October 2006. The marketing company also has strong credit.[6]

Still not convinced? Assume another fact, specifically, that the marketing company pools gas from numerous producers delivering natural gas into pipeline. Instead of marketing just Tiger's 100,000 mmBtu/month, the marketing company markets another 500,000 mmBtu/month of other producers' gas or a total of 600,000 mmBtu/month on that pipeline. The marketing company has reserved firm transportation on that pipeline and has in place purchase and sale contracts downstream with end users. By virtue of its market position, the marketing company also gets a better price. Instead of being paid based on the East Tx index price, the marketing company always gets paid based on the West Ms index price. The net effect over a year's period of time is to increase the value the mineral lessor and lessee obtain by 5% gross or 2.5% after the marketing fee. Now has the marketing company earned its marketing fee? Now does the lessor bear the 2.5% marketing fee? Has the marketing company enhanced the value of the gas?

Once you are convinced that the marketing company has earned its fees, it just takes a change of one fact in the hypothetical to shift the perspective. Now assume that the purchaser is not a third party marketing company but Tiger Production Co.'s own marketing affiliate, Tiger Marketing Co. All other facts being the same, are not the lessor and lessee better off having Tiger Marketing Co. market the production for them?

7. Natural Gas Liquids

Volatility in the relationship of the price of two different commodities, in this case dry gas and natural gas liquids, can also create issues between the mineral lessor and lessee.[7] For instance, assume that Tiger negotiates with the pipeline company and obtains a waiver of the hydrocarbon dewpoint quality specification. As a result, Tiger can continue to extract natural gas liquids from the wellhead gas, selling the liquids in the NGL market and the residue gas to a shipper on the pipeline. Alternatively, now it can also bypass the JT Plant, deliver wet gas to the pipeline and sell it all in the pipeline with higher mmBtu's per cubic foot. The margin between the price of dry gas and natural gas liquids will dictate which one Tiger chooses. When dry gas

---

generally sign the agreement, not because the operator's marketing affiliate is earning the fee but rather because they have no economic alternative. Their mineral lessor inherits the same bad deal.

[6] Enron painfully reminded many producers and royalty owners alike that creditworthiness of natural gas purchasers is important. Purchasers take delivery of your natural gas one month and do not pay for it until the next month or, if they are out of money the next month, never.

[7] The margin between the value of two different commodities, such as crude oil and natural gas, can also be hedged or arbitraged using a spread option. One barrel of crude oil has 6 times more heating value than one thousand cubic feet of natural gas on an mmBtu basis, but it is not always valued that way in terms of dollars. Currently, natural gas is undervalued, on an mmBtu basis, in relation to crude oil, but the margin between the two changes daily. One way to arbitrage this margin is to take a long position on natural gas and a short position on crude oil betting that the price relationship between the two must converge.

prices are more valuable, in relation to the price of natural gas liquids, then Tiger prefers to minimize volume loss and sell as many mmBtu's as possible. Thus, it does not process. On the other hand, when natural gas liquids are more valuable, it sells as many gallons as it can extract from the wellhead gas.

If Tiger pays royalty to its mineral lessor on both liquid and residue gas sales, then the mineral lessor has no complaints. But if Tiger sells its wellhead gas to its marketing affiliate at a delivery point prior to the extraction of natural gas liquids and is always paid and always pays based on the price of natural gas, even when its affiliate is profiting downstream on the margin between prices of natural gas and natural gas liquids, has Tiger breached its obligation to its mineral lessor?

B. FUTURES MARKET

1. The NYMEX Henry Hub Futures Contract

a. Introduction

People often ask me, "What are gas prices?" Sometimes there is not a clear answer. To begin with, some people mean gasoline instead of natural gas. Once you get the commodity straight, you then have to decide whether they mean cash or future. If cash, then one question is where? The price can differ dramatically from hub to hub. Another question is whether they mean the first of the month cash price or the daily price or the daily average price, which, as illustrated above, can also differ dramatically. If, on the other hand, they are inquiring about futures, then to which delivery point and what delivery date are they referring. Generally, when someone asks you "What are gas prices," or the press reports on natural gas prices, they are referring to the New York Mercantile Exchange ("NYMEX") futures contract for delivery at Henry Hub for the following month.

A futures market is defined as a commodity exchange in which futures contracts are traded; a market for a trade (e.g., commodities futures contracts and stock options) that is negotiated at the current price but calls for delivery at a future time. Black's Law Dictionary 983 (7 ed. 1999).

Natural gas futures have been traded on NYMEX since April 3, 1990. By far the most widely traded contract is the NYMEX Henry Hub contract. Its point of delivery is the Henry Hub. Its popularity reflects the liquidity of the underlying Gulf Coast market and its prominence in North America as a price reference for physical transactions. All volume originally was traded through "open outcry" on the NYMEX "Floor." In 2000, the Chicago Mercantile Exchange ("CME") launched the first electronic trading platform, called "Globex." The CME is now the exclusive electronic trading services provider for NYMEX Energy and Metals, including natural gas options and futures contracts. The rapid growth of this trading platform has been remarkable. Now, almost 80% of the daily volume of NYMEX natural gas options and futures contracts are traded on Globex. If future look-alikes being traded over-the-counter via the swap markets and Intercontinental Exchange Inc.'s "ICE" electronic trading platform are included, the NYMEX Floor's portion of the market is now very small.

The only term to negotiate for a NYMEX futures contract is the price. The quantity, quality, timing of delivery and delivery location are all standard.

Futures contracts require that the buyer take delivery and that the seller deliver the commodity at a certain date. Most parties, however, never intend to actually make or take delivery. Instead, they take an offsetting contract position with the exchange that closes out contracts.

b. Physical v. Financial Futures

There is a link between futures contracts and cash contracts. As stated above, the term "basis" can refer not just to the difference between cash prices at two different delivery points, but also to the difference between the cash and future price. The term "contango" refers to a market in which the price of a commodity for future delivery is higher than the spot price or a far future delivery price higher than a nearer future delivery. This is also referred to as a "normal" market, since the premium paid for longer term delivery reflects the costs of holding the commodity for future delivery, including a premium based on time and risk. "Backwardation" is the opposite of contango. In a so-called "inverted market," the price of a commodity for near term delivery is higher than the price for long-term delivery. There are different reasons why a market may become inverted. However, consumers' preference to have the product sooner rather than later generally indicates a perception of shortage in the underlying commodity. By the same token, a market that is deeply in contango may indicate a perception of supply surplus in the commodity.

Though most futures contracts are not settled through delivery, the ability to settle it through delivery of the commodity ensures that futures prices and cash prices are related. For instance, if the futures market becomes overvalued, traders can "short" the market by selling futures contracts and delivering the physical commodity. On the other hand, if the futures market becomes undervalued, traders can buy futures contracts and accept deliveries of the commodity which they can resell at higher spot market prices. The term "arbitrage" refers to the simultaneous buying and selling of identical commodities in different markets with the hope of profiting from the price difference in those markets. The arbitrage between a physical market and a future market of an identical commodity is sometimes called "time arbitrage."

c. Marking To Market

Another unique aspect of a NYMEX futures contract is that the exchange is the counterparty. Thus, there is a buyer or seller for every transaction, but the exchange takes the opposing side of each transaction and assumes legal responsibility for satisfying contract provisions. The exchange clearinghouse backs its guarantee with reserves accumulated from the margin funds that traders are required to deposit in order to open and maintain their positions.

The margin required to deposit in order to open a position is fixed by the NYMEX and depends upon whether the customer is a member or non-member and what month the future contract calls for delivery, with non-members and nearer months generally requiring a larger margin. A broker may require additional margin deposit for an individual customer. Some brokers allow an investor to earn interest on the balance in a margin account, while others do not. However, just posting the initial margin is not all that is required. Margin maintenance, which is somewhat lower than (usually about 75% of) the initial margin, is also required. At the end of each trading day, the customer's margin account is adjusted to reflect the customer's gain or loss. This practice is referred to as "marking to market" the account. When the margin, defined as the net liquidating value plus non-cash deposits in a customer's account declines below the maintenance margin requirement applicable to the open positions carried in such account, then the broker carrying that account makes a "margin call" to the customer, and the customer is required to restore the account to the then prevailing initial margin requirement by the next business day. If the customer does not provide the variation margin, the broker closes out the position by selling the contract. The effect of marking to market is that a futures contract is settled daily rather than at its delivery date. A futures contract is in effect closed out and rewritten at a new price each day.

2. Use Of Futures For Risk Management

A hedge is a transaction one enters into with the intent of offsetting risk from another related transaction. In the commodities context, a hedge is a transaction entered into for the purpose of protecting the value of a commodity from adverse price movement by entering into an offsetting position in the same or a related commodity. There are two common hedging objectives. One is to reduce the risk of unacceptably low returns on capital employed. For instance, if the producer has borrowed capital to purchase or develop an oil and gas asset, its lender often requires hedging to ensure that the producer's returns are sufficient to meet its repayment obligations. The other common objective is to achieve the highest risk-adjusted return on capital employed.

In theory, a producer can use NYMEX natural gas futures contracts for physical deliveries. For instance, assume a producer produces 10,000 mmBtu per month. His point of delivery is Henry Hub, and the quality of his natural gas complies with Sabine Pipeline Co. quality specifications. In early December, the producer sells one natural gas physical future contract for delivery in January at a price of $7.50 per mmBtu of the same quantity of gas at the same delivery point. By the time bid week rolls around in late December, the cash price for delivery at Henry Hub is down to $6.00. The producer decides to make a physical delivery of its natural gas under the future contract and obtain the $7.50 per mmBtu price.

In practice, most futures contracts are settled financially and not by physical deliveries. For example, our hypothetical mineral lessee, Tiger Production Co., would not likely deliver its gas at Henry Hub since its well is located in Northwest Louisiana. Instead, if it held the $7.50 per mmBtu January futures contract as cash prices declined to $6.00, it would liquidate[8] the contract prior to the delivery date and pocket the spread which should approximate $1.50 per

[8] Technically speaking, "unwind" is a term used in the swap market for the process whereby a position or positions, created from a previous swap trade or series of swap trades, is eliminated by entering trades in the equal and opposite direction of the previous trade. The term "liquidate," on the other hand, refers to the process whereby a futures position created from a previous trade or series of trades is eliminated by buying or selling the futures contracts in the equal and opposite direction of the position.

mmBtu. Tiger may continue to produce the well during January, but it sells natural gas produced from the well at the lower cash prices.

In the extreme example in which the hypothetical producer actually makes a physical delivery at Henry Hub, the mineral lessor may have a claim to the higher futures price. In most cases, however, the futures contract operates solely as synthetic hedge or a financial transaction, meaning that the futures contract is not tied to physical delivery of natural gas. In this example, Tiger's royalty owner would have no claims on profits Tiger realized as a result of hedging, nor should it bear losses resulting from Tiger's hedging.

C. OPTIONS MARKET

Options, like futures, are also traded on NYMEX. An option is the right (but not the obligation) to buy or sell a given quantity of a commodity at a fixed price within a specified time. Black's Law Dictionary 1121 (7 ed. 1999). A call is an option to buy a commodity (and require another to sell) at a fixed price even if the market rises. *Id.* A put is an option to sell a commodity (and require another to buy) at a fixed price even if the market declines. *Id.* The term "spread" can mean different things in the natural gas industry, but in this context refers to the difference between the highest price a buyer is willing to pay (bid price) and the lowest price at which a seller will sell (the asked price). *Id.* at 1411.

The definition of several key terms is required to understand how an option works. First, there is the volume. Like the NYMEX Henry Hub futures contract, an option on natural gas is typically measured in terms of 10,000 mmBtu per contract. Second, there is strike price or exercise price. The strike price is the fixed price for which a commodity will be bought or sold under an option contract if the option is exercised. *Id.* at 1207. Third, there is the premium, which is the amount paid to buy an option. *Id.* at 1200. The buyer of an option also incurs transaction costs in addition to the premium. Fourth and finally, there is the expiry date which is the date on which the option expires or ceases to exist. *Id.* at 600.

The buyer of an option can do several things prior to its expiration. First, it can attempt to sell the option. The options market, however, generally has less liquidity than the futures market, and just because one wants to sell does not mean that there is a buyer that wants to buy. Second, the buyer can exercise the option, meaning that it elects to execute its right to either buy (call) or sell (put) the natural gas from or to the seller at the strike price. By exercising the option, the buyer essentially converts the option into a futures contract which it can settle by either making a physical delivery or selling the futures contract in the futures market where there is more liquidity. Third, the buyer of an option can let the option expire worthless and lose its premium and transaction costs. This is one of the appeals of options trading, namely, that the buyer's risk is limited to its premium and transaction costs

.

More options strategies exist than can possibly be covered in this paper. The most basic involve the long call option, the long put option, the short call option and the short put option. More complex options strategies include the bull call spread, bull put spread, covered call, bear put spread, long straddle, short straddle and long butterfly.[9]

One of the most common ways natural gas producers use options to hedge commodity risk is to create a floor or ceiling, or to create both by means of a collar or cost-free collar. A producer can place a floor on its selling price by buying a put option, whereas a gas purchaser can place a ceiling or cap on its purchase price by buying a call option. A collar is a combination of a put option and a call option that has the effect of placing both a floor and a ceiling on the purchasing or selling price. For example, a producer could place a floor and a ceiling on its selling price by buying a put option and selling a call option with the same expiry date. For a zero cost or cost free collar, the premiums for the purchase of the put and the proceeds from the sale of the call cancel each other out, meaning that there is no cost to the producer. A 10 cent collar gives the producer a higher floor and ceiling, but reflects a net premium cost to the producer of 10 cents per unit of measurement.

In almost all cases, an option is purely a synthetic hedge which should not positively or negatively affect the price that the mineral lessee pays the mineral lessor. Theoretically, the owner of a put contract can exercise the option and make a physical delivery under the futures contract. As discussed above with regard to futures contracts, only in this rare, but theoretically possible, case are the rights of the mineral lessor potentially implicated.

D. OVER-THE-COUNTER MARKET

The types of contracts traded in the over-the-counter market ("OTC") are numerous and can include forward contracts, options and swaps. Both an OTC forward contract and an exchange traded futures contract are agreements to buy or sell a commodity at a certain time in the future for a certain price. But, unlike futures contracts, forward contracts are not traded on an exchange. Instead, they are private agreements between two financial institutions or between a financial institution and one of its corporate clients. They are typically negotiated by phone or by computer. Forward contracts and others traded in this manner are commonly referred to as being traded "over-the-counter."

There are several benefits to the OTC market in comparison to the futures market. First, while futures are standardized, some terms of forward contracts, such as the delivery date and location, are negotiable between the parties. Because a party to a forward contract can negotiate the delivery location that party can reduce basis risk by assuring that the terms of the forward contract more closely matches its physical market positions. Second, the margin or collateral

[9] Amaranth Advisors, a hedge fund that lost approximately $6 billion in September of 2006, was reportedly using a spread to go long on the March natural gas futures, while shorting the April futures, betting that natural gas prices historically rise during winter and fall after March, in the so-called "shoulder months" as demand for heating among consumers declines. An uneventful hurricane season in the United States, however, caused the March/April 2007 natural gas spread to contract sharply, not widen, in September resulting in tremendous losses for Amaranth.

requirements may differ depending on the private parties involved, but forward contracts also differ from futures in that they are not marked to market daily. The buyer and seller of a forward contract agree to settle up on the specified date of delivery. Third, most futures are settled up prior to delivery, whereas most forward contracts reach maturity at which time the seller must deliver the commodity or settle in cash. Fourth, most OTC contracts can be traded both before and during trading hours and after the exchanges close.

There are also some detriments to the OTC market. To begin with, because OTC contracts are between two private parties, each counterparty is exposed to the credit risk of the opposite party. Furthermore, there is generally less liquidity in the OTC market. Also, there is greater enforcement through the Commodity Futures Trading Commission and oversight through the National Futures Association of exchange traded futures than OTC transactions.

One of the most common OTC transactions utilized in the natural gas industry is a swap. A swap is an agreement between two parties to exchange, at some future point, one product, either physical or financial, for another. In a simple example of a physical swap, suppose Tiger has a long-term contract with an industrial consumer in South Texas. Tiger's natural gas wells in South Texas, however, have declined, and it no longer has enough production to meet its contractual obligations to deliver. As a result, it seeks more natural gas in South Texas. At the same time, Tiger is selling natural gas on the spot market in Northwest Louisiana. Tiger calls its gas marketer who purchases natural gas at both points of delivery. The gas marketer proposes to purchase natural gas in South Texas and transfer it to Tiger in exchange for Tiger's North Louisiana production. Tiger has effectively exchanged or swapped its natural gas in Northwest Louisiana for natural gas in South Texas.

A physical swap, like a futures contract in which a physical delivery occurs, may implicate the rights of mineral lessors because the transaction is affecting the price that Tiger receives for its natural gas produced in North Louisiana. Also like a futures contract, though, it is much more common for producers to enter into financial swaps than physical swaps.

A financial swap is another type of derivative that obtains its value from the price or prices of one or more financial productions, such as an index or a futures contract. It involves the exchange of payments between two parties, one of which is at a fixed price at the time the swap is entered into, and the other of which is floating. In a simple example of a financial swap, assume that Tiger decides in early December that it desires to sell its gas in the upcoming months of January and February for no less than $6.00 per mmBtu. Its well is now making 3000 mmBtu/day. A natural gas marketer offers to purchase the gas on the spot market at the interconnect point for an index-based price, Henry Hub less a fixed basis differential. At the time of the offer in early December, that net price is slightly greater than $6.00 per mmBtu but could change between early December and the time the price is determined under the purchase and sale agreement. Tiger has bills to pay and cannot make less than $6.00 per mmBtu for the upcoming months of January and February. Accordingly, it accepts the gas marketer's offer, but it also searches for a swap counterparty willing to take the index price risk. Tiger finds an OTC derivatives dealer that is willing to buy a fixed-for-floating swap. The buyer of the swap agrees to pay a fixed price and will receive a floating price. The seller of the swap, being Tiger in this example, receives a fixed price from the other party and pays a floating price to that party. At the time the swap is entered into, the two payments are considered to be of equal value.

One of the most commonly traded natural gas fixed-float swaps are futures look-alike swaps or futures swaps. They mirror the futures contract itself, but at the expiration of the contract, they are settled financially. Since some companies do not have actual futures trading accounts set up with the futures exchanges, such OTC transactions provide them a way to participate in the price action of the futures market. Assume in this case that the fixed price under the swap was \$6.01 per mmBtu, while the floating price – the index based average - ended up being \$5.50 per mmBtu. Tiger's accounting for its sales during the months of January and February would be summarized as follows:

Payment To Tiger For Physical	\$5.50/mmBtu x 3,000 mmBtu/day x 59 days or \$973,500
Swap Payment From Tiger	(\$5.50)/mmBtu x 3,000 mmBtu/day x 59 days or (\$973,500)
Swap Payment To Tiger	\$6.01/mmBtu x 3,000 mmBtu/day x 59 days or \$1,063,770
Effective Result	\$6.01/mmBtu x 3,000 mmBtu/day x 59 days or \$1,063,770

In this example, Tiger effectively protected itself from downward price risk between early December and the delivery dates in January and February by locking in the fixed price. This is another example of a synthetic hedge which, since it is not based on physical deliveries, should neither increase nor decrease the price paid the mineral lessor. Tiger should pay based on the \$5.50 per mmBtu index based price for physical sales.

The problem with this hypothetical is the problem with many hedges: It does not exactly mirror the physical conditions under which Tiger is selling its gas. Tiger is not delivering its natural gas at Henry Hub. Instead, it is selling natural gas at the pipeline interconnect point between the East TX. and Western Ms hubs. Although some marketers may pay for physical gas at other delivery points based on a Henry Hub index price less a larger basis differential, it is more common to sell at a weaker index less a smaller basis differential that more accurate reflects the point of delivery for the sale.

Assume that Tiger is being paid for its physical deliveries based on an East Texas index price, not on a Henry Hub index price. Assume further that the basis differential between the Henry Hub index price and the East TX index price at the time Tiger entered into the transaction in early December was 20 cents. However, by the time that January and February rolled around, that basis differential had grown to 50 cents. Tiger thus netted 30 cents less for its physical sales based on the East TX index price than it had to pay for its swap payment based on the Henry Hub index price. Now, Tiger's accounting for its sales during the months of January and February would be summarized as follows:

Payment To Tiger For Physical	\$5.20/mmBtu x 3,000 mmBtu/day x 59 days or \$920,400
Swap Payment From Tiger	(\$5.50)/mmBtu x 3,000 mmBtu/day x 59 days or \$973,500)
Swap Payment To Tiger	\$6.01/mmBtu x 3,000 mmBtu/day x 59 days or 1,063,770

Effective Result $1,010,670

A basis swap is a derivative that seeks to protect against fluctuations in basis differentials. Basis swaps are priced based on the prices of two underlying financial products, an index price and a futures contract price. The buyer of the basis swap agrees to pay a fixed price to the seller and receive a floating payment from that party in return. The seller, again being Tiger in this example, receives a fixed price from the other party and pays a floating price. The fixed price is the basis differential at the time the transaction is entered. The floating price component is the index for a particular location. Again, at the time the swap is entered into, the two payments are considered to be of equal value.

A basis swap has broader application than this example. In essence, any party that enters into a fixed-price physical transaction at any location other than a futures contract delivery point, and subsequently enters into a futures swap or futures contract to hedge that fixed-price risk, is exposed to basis risk and can use a basis swap to hedge against that risk. NYMEX makes available for trading a series of basis swap futures contracts that are quoted as price differentials between approximately 30 natural gas pricing points and Henry Hub. The basis contracts trade in units of 2,500 mmBtu on the NYMEX ClearPort trading platform.

III. CONCLUSION

A common theme of the factual examples used in this paper is that each one illustrates marketing opportunities or challenges resulting from volatility and particularly basis volatility, that is, the difference between the price of natural gas at different delivery points or at different delivery dates. Another source of volatility that gives rise to the same type of issues is volatility between the price of two different, but related commodities, such as natural gas and natural gas liquids.

Except in rare circumstances, transactions that the mineral lessee enters into in the futures, options and OTC markets are purely financial and have no impact on the relationship between mineral lessor and lessee. Even in the physical market, the mineral lessor is, in large part, along for the ride. Unless it has reserved the right to take in kind, it has no say in how its share of production is marketed, except to the extent that it chooses its lessee. Moreover, the mineral lessor faces a Hobson's choice in choosing its lessee. If it leases to a small independent, it will probably get the same price that the lessee itself receives, but it may not be a very good price. A small lessee may prefer paying a third party gatherer, because it does not have enough production on its own to justify the costs of its own gathering system. Even if it builds its own gathering system, a small lessee will generally sell at the interconnect point, not to an end user or at a downstream hub, because it does not have enough production to secure firm transportation. Even selling at the interconnect point, a small lessee cannot afford to baseload firm volumes, because it does not have excess supply to make up its delivery obligations if its well goes down. On the other hand, if a mineral lessor leases to a large independent or major, then its gas may be sold on better terms, but that higher netback price may not flow through to the lessor.

The upshot is that there is value to aggregating natural gas. In order to take advantage of the volatility in basis, to realize full market values or even to participate in certain markets, a mineral lessee must have reliable, sufficient volumes of natural gas. As a result, the nearest market index price less post production costs to get to that market may be a good indication of market value at the well, but a bright line rule either in favor of mineral lessors (a mineral lessor is always due the nearest spot market index price) or in favor of mineral lessees (payment of the nearest spot market price less post production costs is *per se* a reasonable price) is not practical. Some mineral lessees simply are not in a position to obtain that nearest market index price for themselves or their lessor. Moreover, those lessees that are in a position to realize market values often enjoy that position because of bargaining power that they bring to the table independent of the lease. What constitutes reasonable diligence to secure a market for natural gas and what the mineral lessee owes the mineral lessor as royalty should depend upon the facts and circumstances. Producers do not like the uncertainty of a facts and circumstances rule, but it encourages them to at least consider the interests of their lessors. Although sometimes impractical, a simple meeting with the lessor in some cases can resolve uncertainties about gathering and marketing. As discussed in detail in Leland Horton's portion of this presentation, such an approach is consistent with the "bargained-for exchange test" followed by Louisiana courts.

LEGAL ISSUES AND AUTHORITIES[10]

I. The "Big Picture" As to Current Louisiana Law

Louisiana law is far from settled regarding many of the situations and issues that arise in connection with certain aspects of the ever-evolving practices and marketing options available in the oil and gas industry - including those marketing options and business practices discussed in David A. Barlow's related article and presentation. However, it can be asserted with reasonable certainly that the basic starting point for any thorough legal analysis of such situations is likely found in the "reasonably prudent operator" standard and the implied covenant to market minerals imposed upon lessees by the Louisiana Mineral Code and relevant jurisprudence.[11] Unfortunately for those who like bright-line or purely black-and-white tests, the waters get a bit murky from there. The last two Louisiana Supreme Court opinions directly addressing such issues, at least in some small part, do provide some substantial guidance, but they are somewhat dated and not particularly wide in their respective scope: *Henry v. Ballard & Cordell Corporation*[12] and *Frey v. Amoco Production Company*.[13]

Implicit in those cases is the following, somewhat nebulous guidance: Louisiana courts should apply a "bargained-for exchange" test or rationale in considering questions related to the marketing of minerals and questions as to market value and royalty calculations associated therewith. As such, a mineral lease is considered to represent a bargained-for exchange, with the benefits of that lease flowing directly from the leased premises to the lessee and the lessor, the latter via royalty rights and payments. By that standard, an economic benefit accruing from leased land, generated solely by virtue of the lease and which is not expressly negated by agreement, should be shared between the lessor and lessee in the fractional division contemplated by the lease. That doctrine does not provide a concrete answer to many of the more complicated questions created by present industry practices, marketing options and business structures – but it does establish a framework of analysis for such issues on a case-by-case basis. Unfortunately, that leaves lessees, producers, operators and marketers (and their legal advisors) with some guesswork. The key is to know your contracts, keep those contracts up to date with your business practices, and not avoid renegotiation where necessary. In many instances, the best practice will be to work out some new or revised contractual arrangement with

[10] Much of the research, analysis and text included in this article is taken directly, and indirectly, from research memoranda carefully prepared by Kathryn S. Bloomfield, to whom many thanks are owed.

[11] La. Rev. Stat. 31:122.

[12] *Henry v. Ballard & Cordell Corp.,* 418 So. 2d 1334 (La. 1982).

[13] *Frey v. Amoco Production Company,* 603 So. 2d 166 (La. 1992). Other cases have addressed "market value" leases, and, as in *Henry*, within the context of significantly different economic and practical realities than exist today, but with less thorough analysis than in *Henry*. The Second Circuit Court of Appeal for the State of Louisiana construed a "market value" lease to find under the facts before it that the lessee properly could allocate compression costs to the lessor because the gas had to be compressed in order to market the gas. *Merritt v. Southwestern Elec. Power Co.*, 499 So. 2d 210 (La. 2d Cir. 1986). In 1983, the Louisiana Supreme Court construed a "market value" lease to find that the lessor was not entitled to royalties calculated based on the then higher spot intrastate gas market because the lessor long ago had committed the gas to the federally regulated interstate market under a long-term gas sales contract entered into with the lessor's knowledge. *Shell Oil Company v. Williams, Inc.*, 428 So. 2d 798 (La. 1983).

the relevant lessors and royalty interest owners - rather than assume unnecessary and unpredictable risks. At the end of the day, the Court is going to look to your contract or to the "penumbras" of the Mineral Code for answers.

The *Henry* case involved a claim filed in 1978 concerning various mineral leases executed between 1953 and 1961.[14] In a 4-3 decision, the *Henry* court held that the parties intended for market value to be determined at the time the lessee fulfilled his implied obligation prudently to market the gas by committing it for purchase. To support that decision, Justice Blanche, writing for the majority, first discussed the practicalities of the oil and gas industry. The opinion notes that a lessee's duty to market gas as a reasonably prudent operator is well founded in Louisiana law. The Court observed that only one purchaser of gas was available in the field where the lessor's property was located; therefore, the lessee had the choice of either selling the gas to that one purchaser or not selling it at all. The Court further found that the gas purchase agreement was negotiated in good faith and at arm's length, resulting in an agreement favorable to both the lessor and the lessee. Finally, the Court recognized the then universal industry practice whereby gas purchasers demanded long-term gas sales contracts, and made note of the substantial capital outlay needed for gas purchasers to build the pipeline facilities necessary to transport gas from wells out to interchanges and main lines.

The Court further states that its decision and rationale in *Henry* is based on a similar line of reasoning expressed in a leading case from Oklahoma captioned *Tara Petroleum Corporation v. Hughey.*[15] In *Tara,* the Oklahoma court attempted to preserve, or create, a system whereby lessees and lessors share the same incentives to get the best price possible. That focus assumes that the lessee's duty to share any benefits it receives and its independent incentive to get the best price for its own larger share of production, are the appropriate mechanisms for protecting a lessor's interests.[16]

---

[14] *Henry,* 418 So. 2d at 1335-36. *Henry* is a market-value case in which the operator received the best possible price when it committed gas to a long-term sales contract in 1961. The market prices later outstripped the contract. Construing the lease as a "cooperative venture" and discussing the Oklahoma Supreme Court's decision in *Tara Petroleum Corp v. Hughey*, 630 P.2d 1269 (Okla. 1981), with approval, the Louisiana Supreme Court concluded that market-value leases are satisfied by reasonable long-term contracts entered in good faith. The lessees would not be penalized for their "good faith compliance with their lease obligations."

Note that the dates referenced in the text indicate that the latest discussion of applicable legal principles in Louisiana predates the advent of current market conditions and many of the recently available, or at least popular, practices.

[15] *Tara Petroleum Corp v. Hughey*, 630 P.2d 1269 (Okla. 1981). A careful reading of the majority opinion in *Henry* indicates that Louisiana did not wholeheartedly embrace the rule as stated by the *Tara* court. According to *Tara*, any time the parties base gas royalty payments on the market value of the gas and the lessee markets the gas as a reasonably prudent operator, the court automatically will afford the lessee protection by defining market value as the value represented in the gas sales contract. The *Henry* majority, however, emphasized that its holding was strictly limited to those findings of fact before the court concerning the intent of the parties to the specific leases. However, the court indicated that if it had been faced with different circumstances, the result might have been different: "Had plaintiffs shown that the purpose of the market value royalty clause was to provide them with protection as to price . . . then we would arrive at a different conclusion." Justice Calogero concurred only because he believed that the holding was <u>limited to the specific leases before the court</u> and because he believed the defendants proved the parties' actual intent more convincingly than the plaintiffs.

[16] *Henry,* 418 So. 2d at 1338-40.

That logic, and the similar rule found in *Henry*, was subsequently followed and applied to a different fact situation by the Louisiana Supreme Court in *Frey v. Amoco Production Company*.[17] The *Frey* court applied that same reasoning to the issue of whether a lessee could retain the entire take-or-pay payment it obtained when renegotiating a long-term take or pay contract with a pipeline company - without which renegotiation the pipeline faced financial failure. The *Frey* court framed their conclusions in a somewhat different way (emphasis added):

> "In light of *Henry,* we conclude an oil and gas lease, and the royalty clause therein, is rendered meaningless where the lessee receives a higher percentage of the gross revenues generated by the leased property than contemplated by the lease. <u>The lease represents a bargained-for exchange, with the benefits flowing directly from the leased premises to the lessee and the lessor</u>, the latter via royalty. An economic benefit accruing from the leased land, generated solely by virtue of the lease, and which is not expressly negated, . . . is to be shared between the lessor and lessee in the fractional division contemplated by the lease."[18]

That statement appears to encapsulate the current state of Louisiana law regarding the relationship between lessors and lessees, and the same reasoning will likely be applied to producers, operators and other disputes as to royalty calculations and related marketing practices. It would also be prudent to keep in mind that in other areas of mineral law, Louisiana courts have shown some significant tendencies to strictly interpret lease terms in favor of lessees that are perceived to have been treated unfairly, such as in the now famous *Corbello* case.[19] However, the courts have not shown quite such aggressive enforcement of alleged "implied" duties of lessors and operators.[20] The lesson, again, being to know your contracts, keep them up to date, and do not rely purely on rights that are not clearly expressed in the Louisiana Mineral Code.

II. ROYALTY CALCULATION ISSUES

1. Dramatic Market Fluctuations Often Create Royalty Litigation

Historically, litigation regarding royalties and other related price disputes erupts when there are dramatic changes in commercial gas markets or market disparities between contract prices and the spot market prices. As in many other fields, innovation and competition often result in litigation. Examples are numerous,[21] and this phenomenon is experienced across gas producing jurisdictions.[22] Courts in Texas, Oklahoma, and Colorado, in particular, have arrived

---

[17] *Frey v. Amoco Production Company,* 603 So. 2d 166 (La. 1992).
[18] *Frey,* 603 So. 2d at 174 (citations omitted).
[19] *Corbello v. Iowa Production*, 02-0826 (La.2/25/03), 850 So.2d 686, 694.
[20] *Terrebonne Parish School Bd. v. Castex Energy, Inc*., 2001-2634 (La. App. 1 Cir. 3/19/04), 878 So.2d 522.
[21] *Frey*, 603 So. 2d 166 (royalty litigation arising upon renegotiation of take or pay contract caused by dramatic change in gas prices); *Williams*, 428 So. 2d 798 (royalty litigation resulting from dramatic increase in unregulated intrastate market price compared to federally regulated interstate market price where gas was sold in federal market under long-term contract)(*Williams* is odd to the extent that it seems to follow the *Vela* doctrine, yet, Louisiana rejected the *Vela* doctrine in favor of the *Tara* doctrine, as discussed elsewhere herein.);[21] *Henry*, 418 So. 2d 1334 (royalty litigation ensued after dramatic increase in spot market value of gas, which gas was subject to long-term contract).
[22] *See Piney Woods Country Life School v. Shell Oil Co.*, 726 F.2d 225 (5th Cir. 1984), *cert. denied*, 471 U.S. 1005 (1985) (royalty litigation under Mississippi lease resulting from unprecedented rise in gas prices as a result of actions of OPEC); *Yzaguirre v. KCS Resources, Inc.*, 53 S.W.3d 368 (Tex. 2001) (royalty litigation arising due to

at something approaching bright-line tests for making market value determinations and royalty calculations – although they all differ as to their reasoning and results. Other states, such as Mississippi, have enacted legislation specifically designed to address some of these issues.

Louisiana law has thus far not acquired any strong bright-line tests or express statutory guidance for such matters. Rather, the industry must look to *Henry*, *Frey* and other related cases for insight as to how Louisiana courts will view different types of royalty and marketing issues. That leaves the industry, and its legal advisors, without any hard and fast tests, but with some room to work - with reasonableness and context, perhaps, being the dominant concerns. As such, there is a great deal of uncertainty in assessing the risks associated with new or different business practices and models, and that very uncertainly creates a significant incentive to negotiate, or renegotiate, royalty arrangements as business practices change, rather than after the fact.

2. Market Value Analysis and Common Themes In Royalty Litigation

It is, however, clear that Louisiana recognizes an implied covenant to market minerals produced by a lessee or operator.[23] The implied covenant to market is generally comprised of two components: (i) a duty to make diligent efforts to market production, and (ii) a duty to obtain the best price obtainable by reasonable efforts.[24] In performing its duties, a lessee is not a fiduciary nor does it have a duty to act in the "highest good faith." The standard, as with other implied covenants under an oil and gas lease, is that of a reasonably prudent operator acting in the interests of both lessee and lessor.[25]

Some common threads across royalty litigation are (1) determinations of whether the leases contain clauses that address the matter at hand or whether the leases are ambiguous or silent; (2) the economic and practicalities underlying the gas industry; and (3) the impact of the implied duty to market gas. Typically, a court first determines whether the mineral lease at issue resolves the question and if not (or if the court finds the lease to be silent or ambiguous), the courts consider the implied duty to market gas. Louisiana has held that royalty clauses must be interpreted in accordance with the parties' intent (to the extent such intent can be discerned and recognizing that the parties could not have contemplated every eventuality) in light of the general purposes of a mineral lease (which has been described as a cooperative venture in which the lessor contributes the land and the lessee contributes the capital and expertise to develop the land for minerals for the mutual benefit of both parties), and the physical and economic realities of the gas industry (*e.g.*, unlike oil, gas typically is never stored or transported *by a lessor*).[26]

In the absence of a specific, applicable agreement as to the calculation of royalties under the circumstances at issue, Louisiana, as most jurisdictions, employs a market value approach: "the inquiry . . . shall determine (1) the market price at the well, or (2) if there is no market price

---

disparity in contract price in gas sales contract and market price resulting from price escalation clause in gas sales contract).

[23] *Frey*, 603 So. 2d at 175.

[24] *Id.*.

[25] *McDowell v. PG&E Resources Co.,* 658 So. 2d 779 (La. App. 2d Cir. 1995), *writ denied,* 661 So. 2d 1832 (La. 1995); *see* La. R.S. 31:122.

[26] *See Frey*, 603 So. 2d at 169-179.

at the well for the gas, what it is actually worth there, and 'in determining this actual value every factor properly bearing upon its establishment should be taken into consideration. Included in these are the fixed royalties obtaining in the leases in the field considered in the light of their respective dates, the prices paid under the [gas sales] contracts, and what elements, besides the value as such of the gas, were included in those prices, the conditions existing when they were made, and any changes of conditions, the end and aim of the whole inquiry, where there was no market price at the well, being to ascertain, upon a fair consideration of all relevant factors, the fair value at the well of the gas produced and sold by defendant."[27]

Despite a relative consistency among jurisdictions in articulating the market value test in both market fluctuation litigation or cost allocation litigation, there appear to be two divergent views regarding the proper application and primary focus of that test and, thus, two divergent mechanisms regarding the appropriate way to calculate the market value or price at the wellhead. In particular, that divergence can be seen in various courts' interpretation or application of a lessees' implied obligation to market. Colorado courts have adopted what may be described as a pure implied obligation to market approach, refusing to allocate post-production costs to the lessors until the point in time when the gas is actually "marketable." In contrast, Texas courts have rejected the implied obligation to market approach and typically allocate all post-production costs between lessee and lessor.[28] Although in *Merritt v. Southwestern Electric Power Company*, it seemed that Louisiana rejected the *Colorado* type of approach;[29] in *Frey*, the

[27] *Sartor v. Arkansas Natural Gas Corp.*, 321 U.S. 620, 622-23 (1944) (citing appellate court's decision). Texas articulates the test as follows: "There are two methods used to determine 'market value at the well.' First, the most desired method is comparable sales, *i.e*., sales comparable in time, quality, quantity and availability of market outlets. The second method, used only when comparable sales are not available, is to subtract reasonable post-production marketing costs from the market value at the point of sale." *Ramming*, 390 F.3d at 372.

[28] Following its decision in *Texas Oil & Gas Corp. v. Vela*, 429 S.W.2d 866, 871 (Tex. 1968) (under market value lease, lessee owes royalties based on price of gas in open market although gas actually sold for less under long-term sales contract), the Texas Supreme Court has held that under a market value lease, lessor entitled to open market value although lessee sells the gas for more under a sales contract finding that "there is no implied covenant when the oil and gas lease expressly covers the subject matter of an implied covenant." *Yzaguirre v. KCS Resources, Inc.*, 53 S.W.3d 368, 373 (Tex. 2001). The court concluded that the leases addressed the subject matter of the duty to market because the leases provided for "market value" and "amount realized" as the two measures of calculating royalties. The court found that these leases provided "objective bas[es] for calculating royalties that is independent of the price the lessee actually obtains, [thus] the lessor does not need the protection of an implied covenant." *Id.* at 374.

Notably, the Texas Supreme Court in *Yzaguirre* held that the term "market value" unambiguously meant the prevailing spot market price although the lessees had entered a long-term gas sales contract pursuant to which the lessees sold the gas for much more. The Louisiana Supreme Court in *Henry* (and again in *Williams*) held to the contrary finding that the term "market value" meant the price established by the long-term gas sales contract entered into by the lessees. Interestingly, notwithstanding the different legal conclusions, the result to the royalty owners was the same — they were found entitled to the lower priced royalty bases. Justices Dennis and Lemmon dissented from both *Henry* and *Williams*

[29] *See Rogers v. Westerman Farm Co.,* 29 P.3d 887 (Colo. 2001), *as modified on denial of* rehearing (Aug 27, 2001). *Merritt* appeared to have established a bright line test that post-production costs (transportation and compression costs) are deductible from the royalty owners' share contrary to the implied obligation to market analysis employed by *Frey*. *Merritt* involved gas production from a well which was transported via gathering lines to an existing pipeline. However, due to low flow pressure from the well into the gathering system, the lessee had to install compressors in order to get the gas to the pipeline. The court reasoned that there was no market or purchaser for the gas as it existed at the wellhead due to its low pressure, thus, there was no market at the well. To be marketed, the gas had to be compressed. Relying on *Martin v. Glass*, 736 F.2d 1524 (5th Cir. 1984) (Texas law applied and post-production costs found deductible), the court employed the reconstruction approach to the market value "at the

Louisiana Supreme Court expressly adopted and recognized an implied obligation to market. The Louisiana Supreme Court applied that obligation in light of the economic and practical realities of the gas market, tempered by the facts and circumstances of the particular case and subject to a reasonableness test.[30] In applying that test, the, *Frey* court quoted *Henry* with approval,[31] and concluded that the interpretation of "the royalty clause[[32]] . . . is rendered meaningless where the lessee receives a higher percentage of the gross revenues generated by the leased property than contemplated by the lease," and articulated the benefits or bargained-for exchange test stated above.

In short, under the now prevailing Louisiana rule, the lessee may not be permitted to calculate royalty payments in such a manner that permits the lessee to receive a greater part of the gross revenues than the fractional division stated in the mineral lease and if the lessee derives an economic benefit that accrues from the leased land, it should be shared in the fractional division set by the lease.

---

mouth of the well," and held that the compression costs properly were deductible from the royalty owners' share. *Merritt* briefly noted the implied obligation to market imposed on lessees, but interpreted it to mean that "[s]ince marketing the minerals benefits both the lessee and the royalty owner, the royalty owner should bear a proportionate share of the marketing costs." *Merritt*, 499 So. 2d at 214. This statement is of doubtful precedential value because the lessee also is subject to the implied duty to produce gas yet, the lessee is not entitled to share production costs with the lessor.

It is doubtful that *Merritt* remains viable as a bright line test in light of *Frey*, current practices in the gas markets, and *Merritt's* particular reading of the implied obligation to market. Moreover, *Merritt* relied on *Martin v. Glass*, which interpreted Texas law. And, Texas follows the *Vela* doctrine, named after *Texas Oil & Gas Corp. v. Vela*, 429 S.W.2d 866 (Tex. 1968), but, the Louisiana Supreme Court rejected *Vela* in favor of the *Tara* doctrine, named after *Tara Petroleum Company v. Hughey*, 630 P.2d 1269 (Okla. 1981). *See Henry*, 418 So. 2d 1334 (adopting *Tara* and rejecting *Vela*).

The result in *Merritt* nonetheless is correct under the *Frey* analysis, apropos the practical and economic realities in existence at the time. The gas simply could not be marketed upon production because of its low pressure. In *Frey*, there was no issue that the gas was not marketable and in fact, readily had been marketed via the take or pay contracts.

[30] *Frey* is not a departure from previous Louisiana jurisprudence; Louisiana consistently has considered the practical and economic realities and the implied obligation to market as crucial factors that underlay the determination of royalty payments. *See Henry*, 418 So. 2d 1334 (court relied on the implied obligation to market and the economic reality at the time that the long term gas contract was reasonable when executed, thus, the lessor could not recover royalties based on the subsequent increases in the spot market); *Williams*, 428 So. 2d 798 (relying on implied duty to secure market for produced gas, court found that the long term gas contract previously entered into by lessee was reasonable and lessor not entitled to royalties based on subsequent higher spot market value); *Wall*, 152 So. 561 (court found a market existed at the well because there were several fields in the area into which pipelines already existed and various companies competitively bid and bought gas directly from the fields, but noted in *dicta* without expressly discussing implied duty to market that were there was no market at the well and gas had to be transported some two miles, lessee would be entitled to deduct reasonable transportation costs from royalty owner's share).

[31] "[T]he process reflects our appreciation of the cooperative nature of the lease arrangement as well as an understanding of the economic and practical considerations underlying the royalty clause. Retention by Amoco of the entire take-or-pay payment would permit Amoco to receive a part of the gross revenues from the property greater than the fractional division contemplated by the Lease." Such a result can not be countenanced by this Court." *Frey*, 603 So. 2d at 174 (citation and internal quotations omitted).

[32] The royalty clause in *Frey* was not a "market value" clause, but rather a royalty clause on "gas sold by the Lessee [of] one-fifth (1/5) of the amount realized at the well from such sales." Notwithstanding this difference, the reasoning of *Frey* appears to be apt to a "market value" lease, particularly because *Frey* relied heavily on *Henry*, which involved a "market value" lease.

3. Royalty Litigation Over Costs Allocation

One particular area of current activity and concern is the issue of cost allocation, i.e., whether a lessee can deduct the costs of bringing produced gas to a commercial market from the royalty owners' shares. That question has resulted in another apparent split in state laws, with some state courts frequently disallowing deductions for post-production costs and others more often permitting lessees to deduct post-production costs.[33] The prudent course in Louisiana, at least in the present climate, is to look to the relevant leases and related contracts – with courts likely to apply a "benefit of the bargain" test and a reasonable operator duty to resolve any disputes . In any event, documented actual costs are more likely to escape serious scrutiny than more nebulous fees and costs, such as for "administrative" or "marketing" activities. Negotiating such matters with specificity will likely save quite a bit of risk and guesswork down the road.

C. ALLOCATION OF GATHERING AND TRANSPORTATION COSTS.

As briefly noted above, cost allocation is an area of significant concern, and risk, in the industry. In Louisiana, generally, a royalty owner does not directly bear production related costs or costs to bring minerals to the "wellhead." However, post-production charges such as transportation from the field, compression charges, actual marketing expenses, and dehydration costs may be deductible from royalty and overriding payment. For example, if the lease provides for payment of the market value "at the well" or "at the mouth of the well," and the actual sale of production takes place at some point beyond the wellhead, reasonable costs incurred by the lessee beyond the wellhead may well be deductible in calculating royalties.[34] In *Piney Woods,* the court noted:

> We emphasize, however, that processing costs are chargeable only because, under these leases, the royalties are based on value or price at the well. Processing costs may be deducted only from valuations or proceeds that reflect the value added by processing. Thus, processing costs may not be deducted from royalties for gas sold at the well, because the price of such gas is based on its value before processing.[35]

---

[33] *Compare Merritt v. Southwestern Elec. Power Co.*, 499 So. 2d 210 (La. App. 2d Cir. 1986) (lessor shares costs of getting gas to market with lessee);[33] *Creson v. Amoco Production Co.*, 10 P.3d 853 (N.M. App. 2000) (Under New Mexico law, post-production costs deductible); *Piney Woods*, 726 F.2d 225 (applying Mississippi law, court found processing costs deductible); *Ramming v. Natural Gas Pipeline Co. of America*, 390 F.3d 366 (5th Cir. 2004) (applying Texas law to find post-production costs deductible); *Martin v. Glass*, 571 F.Supp. 1406 (N.D. Tx. 1983); *with Rogers v. Westerman Farm Company*, 29 P.3d 887 (Colo. 2001) (costs are not shared between lessor and lessee until gas is "first marketable"); *TXO Prod. Corp. v. Oklahoma*, 903 P.2d 259 (Okla. 1994) (dehydration and gathering costs not deductible from lessor because lessee is required to make gas marketable); *Fox Wood III v. TXO Production Corp.*, 854 P.2d 880 (Okla. 1992) (lessee bears compression, transportation, gathering and dehydration costs, *i.e.*, costs incurred until gas is fit to enter pipeline); *Schupbach v. Continental Oil Company*, 394 P.2d 1 (Kan. 1964) (compression costs not deductible); *Hanna Oil & Gas Co. v. Taylor*, 759 S.W.2d 563 (Ark. 1988) (lessee could not deduct compression costs).

[34] *See Merritt,* 499 So. 2d 210; *Piney Woods*, 726 F.2d at 240.

[35] *Id.; see generally* 3 H. Williams, *Oil & Gas Law* § 645 at 595, 598-609 (1992).

That statement obviously provides some basis for making business and royalty-calculation decision, but just as obviously leaves some gray areas - largely due to its fact-specific nature.

1. Gathering Costs

As to gathering costs, *Merritt* suggests that such costs may be allocated proportionately to the royalty owners. However, as discussed above, *Frey* articulated a benefits test in terms of *gross* (not net) proceeds based on the implied duty to market gas imposed on lessees – which may lead to different results given different contractual language or different facts.[36] *Merritt* was also decided under different industry circumstances than exist now. Moreover, as explained by other jurisdictions that rely on the implied duty to market, imposing such gathering costs against royalty owners renders them, in some respects, indistinguishable from working interest owners, who, unlike royalty owners, have a say in the costs incurred.[37] Important questions for any court faced with such allocation issues will be whether the gathering activities were necessary to move the product off the lessees property in order to market the gas and whether the additional costs resulted in additional value for the lessor and the lessee.

Note also that in Louisiana the historical conduct of the parties in performance of their contracts is highly relevant, if not determinative, of what the parties intended by their agreements.[38] Where a producer historically has not allocated gathering costs against the royalty owners, it may be difficult or "unreasonable" to change that course of dealing without changing or clarifying the underlying documents. Again, Louisiana courts will likely factor their views on reasonableness and good faith into their analysis – keeping in mind the "benefit of the bargain" originally negotiated by the parties.

2. Transportation Costs To Downstream Markets

Transportation costs and other related costs incurred further downstream, beyond an interchange point, are even more likely to be allocable to the royalty owners, unless the relevant contracts dictate otherwise. The key is the existence of a viable commercial market at the relevant interchange point. Under those circumstances, a producer should be able to calculate royalties based on the downstream higher market, and thereby reasonably allocate the transportation costs to the royalty owners as costs incurred to market the gas for a better price, *i.e.*, to add value to the product.[39] Neither the Louisiana Supreme Court nor the Louisiana Legislature has directly addressed the notion of "added value" in such circumstances; however, the Supreme Court long ago suggested that result in *Wall*, when the court noted that were there

---

[36] *See Frey*, 603 So. 2d at 174.
[37] *See*, *e.g.*, *Fox Wood III*, 854 P.2d at 882-883 (collecting cases) (holding lessee's duty to market includes the cost of preparing the gas for market apropos the fact that "the mineral owner's decision whether to lease or to become a working interest owner is based upon the costs involved. . . . [W]orking interest owners who share costs under an operating agreement have input into the cost-bearing decisions. The royalty owners have no such input after they have leased. In effect, royalty owners would be sharing the burdens of working interest ownership without the attendant rights").
[38] *See* La. Civ. Code arts. 2054, 2056.
[39] *See Rogers*, 29 P.3d at 900-905, 906; *TXO Prod. Corp.*, 903 P.2d at 262-63.

not a commercial market in the field, a lessee could deduct costs of transporting the gas to a downstream market.[40]

IV. TRANSACTIONS BETWEEN AFFILIATED ENTITIES

Although affiliated companies have always operated in the oil and gas industry, one of the major developments following open access to interstate pipelines has been the creation of affiliated companies by producers seeking to engage in additional aspects of the industry (and often to conduct businesses that were once the sole province of the pipeline companies). For example, a producer now has the ability to sell to purchasers at the wellhead, or any number of points between the wellhead and the end user. The producer also has the ability to engage in new business activities such as aggregating supply, packaging supply, seeking out downstream buyers, gathering, treating, processing, storing, delivering to end users, and guaranteeing levels of service to end users or intermediate marketers. However, when gas is sold to entities affiliated with a producer, significant questions may arise as to the proper calculation of royalties for market value leases, in connection with both the applicable contracts and implied covenants.

A prudent business planner often creates such affiliates to isolate business functions and risk "packages" in separate corporate entities. The general expectation is that separate corporate entities will be respected as such by the courts, except in the most extreme circumstances. Such corporate separateness is typically disregarded only when the business model or its application is proven to be fraudulent in fact.

Transactions between such affiliates, however, may allow a producer to gain indirectly a benefit not shared with the royalty owner, either in pricing or through the inflation of affiliate costs or services. When this happens, courts may take a heightened interest and apply an additional duty of good faith. Courts may find that the parties' interests are not longer aligned when the producer is obtaining a significant "collateral benefit" from a transaction, but not sharing that benefit with the royalty owner. Such circumstances may lead to damages or a theoretical "unraveling" of the separateness of the entities involved.

The bottom line is that the creation and maintenance of separate corporate entities is useful and prudent in many circumstances. There is no inherent "foul play" when affiliates deal with one another in the field. However, when transactions between affiliates take place, the

---

[40] *Wall*, 152 So. at 971-18. In *Wall*, a viable competitive commercial market existed in the field. *Wall*, 152 So. at 917-18. The trial judge "deducted from the price received by defendant the expense of piping the gas to the place where it was sold and held that what remained was the 'market price' of the gas. His ruling would unquestionably be correct if, as a matter of fact, the gas had no 'market value' in the field. But we find as a fact that it did." *Id.* In so ruling, the court found that the evidence "shows further that natural gas has a market value in each of the fields; that pipelines have been built into each of them; and that the companies purchase gas in each of them at competitive prices. The testimony shows further that 4 cents per thousand cubic feet is the average price paid in these fields and that the price paid plaintiffs was based on that average. In the Elm Grove, Richland, and Ouachita-Morehouse fields, the price is 3 cents, but in some of the others it is 4 cents, and in one it is 5 cents. Therefore the price of 4 cents paid by defendant in this case was not an 'arbitrary price' as suggested by counsel for plaintiffs, but the average price paid in the North Louisiana territory. That is the 'market price' in the fields and must be accepted as the basis of settlement in this case." *Id.* at 918. *Merritt's* results similarly can be explained in terms of the value added approach.

parties should ensure those affected by the transaction will be treated no less favorably than if the transaction were between non-affiliated entities.[41] To operate otherwise is to invite litigation and damages.

V. LOUISIANA PRESCRIPTIVE PERIOD FOR ROYALTY CLAIMS

Generally speaking, the Louisiana prescriptive period for royalty claims is three years. La. Civ. Code Art. 3494 provides in relevant part that:

> The following actions are subject to a liberative prescription of three years:
>
> * * *
>
> (5) An action to recover underpayments or overpayments of royalties from the production of minerals, provided that nothing herein applies to any payments, rent, or royalties derived from state-owned properties.

Louisiana courts have consistently rejected lessor attempts to circumvent the three-year prescriptive period. For example, in *Acadia Holiness Association v. IMC Corp.* the lessor sought to recover additional payments from its lessee based on the Supreme Court's holding in *Frey*.[42] The lessor in *Acadia* attempted to characterize its claim as an attack upon the lessee's performance of its "prudent operator" duties, subject to the ten-year prescriptive period governing contractual disputes, rather than an action to recover additional royalties subject to the three-year period. The court found, however, that the lessor's claim was clearly for additional royalties, and that therefore the three-year period controlled.

Similarly, efforts to extend the three-year period couched in terms of a delayed commencement or tolling of the prescriptive period have not met with success. Lessors frequently assert that, under the doctrine of *contra non valentem*, the three-year prescriptive period was suspended because they were unaware of their claim. Under Louisiana law, *contra non valentem* is a judicially created principle according to which the running of prescription can be delayed because the claimant was prevented from asserting his claim. One example in the royalty context is the thirty-day delay that the lessor must experience between giving written notice of its claim and filing suit.[43] More common, however, is for a lessor to rely on the "discovery rule" of *contra non valentem* (*i.e.*, the rule according to which prescription is suspended as long as the claimant does not know of its claim, and should not have known of the claim through the exercise of reasonable diligence).

Thus far, the majority of the reported decisions have rejected royalty owners' reliance on the "discovery rule" of *contra non valentem*, thereby confirming that *contra non valentem* is an

---

[41] *See Wegman v. Central Transmission, Inc*., 499 So. 2d 436 (La. App. 2d Cir. 1986).
[42] *Acadia Holiness Ass'n v. IMC Corp.,* 616 So. 2d 855 (La. App. 3d Cir. 1993),
[43] *Agurs v. Amoco Production Co.,* 465 F.Supp. 154 (W.D. La. 1979).

exceptional remedy that is to be construed strictly. It is well established that the burden is on the party asserting *contra non valentem* to prove that the doctrine applies. In both *Edmunson v. Amoco Production Co.*, and *La Plaque Corp. v. Chevron U.S.A. Inc.,* the courts found that the plaintiff royalty owners had not satisfied their burden, because the royalty owners knew, or should have known through the exercise of reasonable diligence, about the facts underlying their claims of underpayment.[44] Significant factors in these decisions included: the availability of relevant information either on, or discernible from, both the royalty check-stubs and public sources; the responsiveness of the lessees to royalty owner requests for information; the fact that other royalty owners had filed suit on identical or similar claims within the three-year period; and the sophistication of the royalty owners.[45] In contrast is the Fifth Circuit's decision in *Frey v. Amoco Production Co.*, in which the court held that prescription was suspended on royalty claims relating to a variety of issues (including miscalculations arising from tax rebates, gas balancing accounting, and lease-use gas), because, in the court's view, the royalty owners had no reason to suspect that any errors had occurred in connection with these issues.[46]

An issue that frequently arises in royalty disputes involving the "discovery rule" of *contra non valentem* is the scope of the lessee's duty to inform the lessor of the circumstances surrounding the lessee's marketing of lease production. In such disputes, the lessor generally asserts that it did not have sufficient information to bring its royalty claim because the lessee controlled the relevant information and failed to provide that information to the lessor. The lessee generally counters by arguing that: (1) the Louisiana "check-stub" statute — article 212.31 of the Mineral Code — sets forth all of the information that a lessee must provide with its royalty payments; (2) for the lessee to incur any greater duty to initiate the disclosure of additional marketing information would subject the lessee to a fiduciary obligation, in contravention of the express statement in Mineral Code article 122 that a lessee "is not under a fiduciary obligation to his lessor;" and (3) if the lessor had made a timely request for information beyond that required to be shown on the royalty check-stub, the lessee would have complied with any such request.[47]

VI. SOME TENTATIVE CONCLUSIONS ON PRESENT LOUISIANA LAW

Although related issues have been widely litigated in various producing jurisdictions, Louisiana jurisprudence interpreting royalty obligations under a "market value" clause is scant. However, extrapolating from the general principles discussed above and found in older Louisiana cases (also discussed above), our conclusions are:

1. In most cases, Louisiana courts are likely follow a "bargained-for exchange" test or rationale - where the lease represents a bargained-for exchange with the benefits flowing directly from the leased premises to the lessee and the lessor, the latter via royalty. An economic benefit accruing from the leased land, generated solely by virtue of the lease, and which is not expressly negated, is

---

[44] *Edmunson v. Amoco Production Co.,* 924 F.2d 79 (5th Cir. 1991), and *La Plaque Corp. v. Chevron U.S.A. Inc.,* 638 So. 2d 354 (La. App. 4th Cir. 1994),
[45] *See also Chevron U.S.A., Inc. v. Landry*, 93 C.A. No. 1286 (La. App. 1st Cir. 1994) (unreported decision rejecting application of *contra non valentem* to suspend prescription on royalty claims).
[46] *Frey v. Amoco Production Co.,* 943 F.2d 578 (5th Cir. 1991),
[47] *See* La. R.S. 31:212.31.

to be shared between the lessor and lessee in the fractional division contemplated by the lease. That analysis necessarily involves some application of the "reasonably prudent operator" standard.

2. There is no inherent "foul play" when affiliates deal with one another. However, when transactions between affiliates take place, the parties must ensure those affected by the transaction will be treated no less favorably than if the transaction were between non-affiliated entities. Such transactions will often be subjected to heightened scrutiny.

3. Price charged to or by affiliates will likely hold up where they appear to be a reasonable and appropriate against other similar transactions between non-affiliates, or where there is a distinct and justifiable added value. The most reasonable possible price in affiliate situations will likely involve reference to market factors apart from internal negotiations between the affiliates.

4. If there is a market at the well, the costs of transporting the gas from a given exchange to the downstream market by an affiliate may well should be shared proportionately with the royalty owners.

5. Louisiana Courts typically uphold and strictly enforce the three-year prescriptive period for royalty claims in Louisiana.

Of course, it is vitally important to know and understand the contracts and agreements at issue in any particular case. Good business and risk management practices may depend upon keeping contracts up-to-date with regard to changing industry practices and marketing options. Otherwise, it may become a matter for the courts. If in doubt as the relevant terms and duties, renegotiate or amend the existing agreements to clarify the "benefits of the bargain" for each of the parties involved.

One possible solution to these issues, from a practical standpoint, may be the creation of a risk/cost matrix that maps out different situations that need to be addressed in particular contracts and the related negotiations. A master risk/cost matrix may then be tailored to individual properties and circumstances to provide a blueprint whereby all necessary issues are addressed (or not addressed) in the initial agreements or any amendments made thereto.