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An Overview of Current Louisiana Law Regarding Implied Lease Obligations

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I. *The "Big Picture" as to Current Louisiana Law*[1]

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.[2] 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*[3] and *Frey v. Amoco Production Company.*[4]

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

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[1] 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.

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

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

[4] *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).

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 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.[5] 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

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[5] *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.

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.*[6] 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.[7]

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.*[8] 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. *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 to

6 *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 *limited to the specific leases before the court* and because he believed the defendants proved the parties' actual intent more convincingly than the plaintiffs.

7 *Henry,* 418 So. 2d at 1338-40.

8 *Frey v. Amoco Production Company,* 603 So. 2d 166 (La. 1992).

be shared between the lessor and lessee in the fractional division contemplated by the lease."[9]

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.[10] However, the courts have not shown quite such aggressive enforcement of alleged "implied" duties of lessors and operators.[11] 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,[12] and this phenomenon is experienced across gas producing jurisdictions.[13] Courts in Texas, Oklahoma, and Colorado, in particular, have arrived at something approaching bright-line tests for making market value determinations and royalty calculations – although they all differ as to their reasoning and results.

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9 *Frey*, 603 So. 2d at 174 (citations omitted).

10 *Corbello v. Iowa Production*, 02-0826 (La.2/25/03), 850 So.2d 686, 694.

11 *Terrebonne Parish School Bd. v. Castex Energy, Inc.*, 2001-2634 (La. App. 1 Cir. 3/19/04), 878 So.2d 522.

12 *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.); *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).

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

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.[14] 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.[15] 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.[16]

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

14 *Frey*, 603 So. 2d at 175.

15 *Id.*.

16 *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.

the physical and economic realities of the gas industry (*e.g.*, unlike oil, gas typically is never stored or transported *by a lessor*).[17]

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 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."[18]

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.[19] Although in *Merritt v. Southwestern*

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

[18] *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.

[19] 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

Electric Power Company, it seemed that Louisiana rejected the Colorado type of approach;[20] in *Frey*, 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.[21] In applying

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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*

20 *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 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.

21 *Frey* is not a departure from previous Louisiana jurisprudence; Louisiana consistently has considered the practical and economic realities and the implied obligation to

that test, the *Frey* court quoted *Henry* with approval,[22] and concluded that the interpretation of "the royalty clause[[23]] . . . 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.

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.[24] The prudent course in Louisiana, at least in the present climate, is

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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).

22 "[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).

23 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.

24 *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);[24] *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 Amer-*

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.

III. *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.[25] 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.[26]

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

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ica, 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).

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

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

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.[27] *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.[28] 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.[29] 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.[30] 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

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27 *See Frey*, 603 So. 2d at 174.

28 *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").

29 *See* La. Civ. Code arts. 2054, 2056.

30 *See Rogers*, 29 P.3d at 900-905, 906; *TXO Prod. Corp.*, 903 P.2d at 262-63.

Wall, when the court noted that were there *not* a commercial market in the field, a lessee could deduct costs of transporting the gas to a downstream market.[31]

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

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31 *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.

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 parties should ensure those affected by the transaction will be treated no less favorably than if the transaction were between non-affiliated entities.[32] 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*.[33] 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

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32 *See Wegman v. Central Transmission, Inc.*, 499 So. 2d 436 (La. App. 2d Cir. 1986).

33 *Acadia Holiness Ass'n v. IMC Corp.*, 616 So. 2d 855 (La. App. 3d Cir. 1993).

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.[34] 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 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 *Edmundson 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.[35] 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.[36] 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.[37]

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

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34 *Agurs v. Amoco Production Co.*, 465 F.Supp. 154 (W.D. La. 1979).

35 *Edmundson 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).

36 *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).

37 *Frey v. Amoco Production Co.*, 943 F.2d 578 (5th Cir. 1991).

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 checkstub, the lessee would have complied with any such request.[38]

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 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

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38 *See* La. R.S. 31:212.31.

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.