ACQUIRING UPSTREAM ASSETS VIA JOINT VENTURES

An In-Depth Study of Deal Structures, Key Negotiating Points, Drafting Tips, and Relevant Law

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I. Introduction and Scope

This paper will cover the general topic of acquiring upstream oil and gas assets through transactions other than traditional purchase and sale agreements, such as multi-well farmout and participation agreements, drilling fund agreements, acquisition alliances, and joint exploration and development agreements. It will include discussions of certain deal structures, key negotiating and drafting points, carried interests, AMI issues, exit strategies, and several relevant title diligence, tax, and other current and emerging legal issues and developments.[2]

Adding something new to a topic that many of our peers have covered so thoroughly in other articles and speeches is a challenging task.[3] This paper would be incomplete if it did not include some of the same general overview and discussion that such other specialists have already covered. In addition to that general overview, however, we will attempt to cover in detail some unique issues and law that we have not previously seen discussed in detail in a CLE setting. By doing so, our hope is that even the most experienced oil and gas deal lawyers may either learn some new law or learn to spot and address some new issues that they may not have previously encountered.

Because many of these intricate issues, along with much of the relevant law, are encountered in traditional farmout agreements, we begin with an analysis of that structure.

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[1] The authors are members of Akin Gump's Global Energy Transactions practice in Houston, with a primary focus on upstream M&A transactions. The authors wish to acknowledge the following other members of the firm for their input and assistance: Thomas Weir, Partner, Tax; William D. Morris, Partner, Global Energy Transactions (and leader of the firm's derivatives transactions practice); Paul B. Hewitt, Partner, Antitrust and Unfair Competition (and leader of that practice); Mollie McGowan Lemberg, Counsel, Antitrust and Unfair Competition; and Adam Garmezy, Associate, Global Energy Transactions.

[2] Our primary geographical focus will be on U.S. domestic transactions.

[3] *See*, *e.g.*, Debra J. Villarreal, *Development Agreements*, Rocky Mountain Mineral Law Foundation Shale Plays Institute (2010); Debra J. Villarreal, *Exploration and Development Agreements*, 31st Annual Institute of the Energy and Mineral Law Foundation (2010); John B. Connally IV and Patrick T. Maguire, Recent Trends in Joint Ventures for Shale Oil and Gas and Other Capital-Intensive Oil and Gas Projects, Rocky Mountain Mineral Law Fifty-Seventh Annual Institute (2011); Jeffrey S. Munoz, *Emerging Trends in Oil and Gas: It's All About Shale*, CAIL Institute for Energy Law 64th Annual Oil and Gas Law Conference (2013); Michael P. Darden, Robin S. Fredrickson, Michael R. King, and Jeffrey S. Munoz, *Joint Ventures in Shale Plays*, The University of Texas Journal of Oil, Gas and Energy Law 10th Annual TJOGEL Symposium (February 19, 2015); for an excellent related and relevant article, *see also* David H. Sweeney, Preston Cody, Susan Lindberg, and Michael P. Darden, "*Fracturing Relationships: The Impact of Risk and Risk Allocation on Unconventional Gas Projects*," CAIL Institute for Energy Law 65th Annual Oil and Gas Law Conference (2014).

II. Multi-Well Farmout Agreements

Under a farmout agreement, a party who owns the right to drill wells on a property (the "Farmor") agrees to assign some or all of its interest in the property to another party (the "Farmee") in exchange for exploration of the property by the Farmee, who becomes the "Operator" of the farmed out interest. In a typical joint venture farmout, the Farmee carries the Farmor's share of costs to drill wells on the property for a period of time, and earns an undivided working interest in all or portions of the property by satisfying certain drilling obligations.

A. Drivers and Components of Consideration in Typical Farmouts

The owner of undeveloped acreage may have various reasons to farm out an interest in the acreage to another party. Perhaps the two most significant reasons are cost and technological expertise. The cost of developing a property can be substantial, particularly if the target for exploration is a new or speculative formation, or the planned operations involve horizontal wells, hydraulic fracturing, or new technology. A Farmor may be best able to leverage its acreage position by partnering with a Farmee who has the financial resources to make a large capital investment in drilling, or one who has the experience to drill wells in the target formation in a more efficient manner. For example, a Farmor may own leases under which it has been drilling conventional vertical wells, but under which a shale play in a shallower (or deeper) formation has not yet been developed. Rather than drill wells into the shale formation itself, the Farmor may be better off bringing in an experienced shale operator in the area as a Farmee, since the shale operator will typically have the expertise to drill and frac wells in the shale formation that are more successful and less costly than ones the Farmor could drill itself. The Farmee, meanwhile, would gain an acreage position in an upside play in return for the leveraging of its expertise and capital resources.

Other factors may also drive the decision to enter a farmout. A producer may face impending lease expirations and need a partner to drill wells to preserve the leases, or the producer may be willing to forgo some of its interest in its acreage so another company can share in the exploration risk. The weight of the particular drivers of a farmout will typically influence the structure of the transaction and the components of the consideration.

In general, the five primary components of the consideration in a farmout transaction are as follows:

1. Cash: A Farmee will typically make an upfront cash payment for the right to enter into the joint venture. The payment is usually based on the net acres to be delivered to the Farmee (assuming no production is included).[4]

2. Farmor's Retained Working Interest: A Farmor will generally want to retain a portion of its interest in the acreage in order to maintain some of the long term upside in the prospect area. The size of the Farmor's retained interest may be affected by factors such as the

[4] In some cases, the Farmor may have acquired seismic data on the acreage, in which case the cash payment may also include reimbursment of the seismic acquisition costs.

size of the drilling program and the expected budget for the joint venture, as well as the size of the cash payment.

3. Carried Working Interest: A Farmee may agree to bear the costs attributable to the Farmor's retained working interest for an agreed number of wells or up to an agreed dollar amount.

4. Continuous Drilling Obligations: The parties to a farmout may negotiate the number of wells that must be drilled for the Farmee to earn its acreage in the prospect area, the frequency with which such wells must be drilled, and the particular depths to be earned by the Farmee.

5. Retained ORRI: The Farmor may want to increase its future revenues by retaining an overriding royalty interest ("ORRI") in the prospect area in addition to its retained working interest. As mentioned above, many shale plays lie above or below conventional producing formations. Often, the original oil and gas leases for exploration of the conventional formation were acquired decades earlier when lease royalties as low as 1/8 were the market royalty – resulting in a higher net revenue interest to the lessee than under most modern leases. If the leases have been continuously maintained in force and effect by virtue of the operations or production from the conventional formation, the Farmor has the advantage of being able to negotiate for a retained ORRI and still deliver to the Farmee a net revenue interest that is in line with current market expectations for newly acquired leases.[5]

The following sections will discuss in more detail various issues that arise when structuring a typical farmout, how those issues may affect the components of the consideration for the farmout, and drafting considerations for dealing with those issues.

B. The Prospect Area and Prospect Depths

The farmout agreement must contain a valid description of the lands and depths covered thereby (the prospect area and prospect depths). The prospect area is often described by reference to an exhibit containing descriptions of the leases or pooled units covering lands within the prospect area, or a plat outlining the prospect area.

Careful attention must be given to ensure that the description of the prospect area satisfies the statute of frauds. Generally, describing the prospect area by reference to one or more other agreements, maps, or plats will satisfy the statute of frauds, provided that the both the description of the referenced document(s) and the property description within such document(s) are sufficiently certain.[6] A drafter should be sure to review the language of the description to ensure it does not create ambiguities that potentially invalidate the land description under the statute of frauds.[7]

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[5] However, the parties – particularly the Farmor – should be aware of the tax implications of retaining an ORRI, as discussed below in Section VII.C.

[6] *See, e.g., Pick v. Bartel*, 659 S.W.2d 636, 637 (Tex. 1983); *Padilla v. LaFrance*, 907 S.W.2d 454, 460 (Tex. 1995) (citing *Adams v. Abbott*, 254 S.W.2d 78, 80 (Tex. 1952)).

[7] For a further discussion regarding the statute of frauds, see Section IV.A.1 below.

Similar care should be taken when describing the depths covered by a farmout. Generally, one should avoid merely naming a target formation, because the exact depths covered by a formation differ by location, and different parties may have different understandings of the depths at which a particular formation begins and ends. Instead, a strong description of a prospect interval will include a reference to a well-described log from a well-described marker well, complete with measurements for the upper and lower depths of the target formation. For example, in a farmout agreement targeting the Eagle Ford Shale and Buda formations, the description of the prospect interval might read:

> Those subsurface depths located between the stratigraphic equivalents of the top of the Eagle Ford Shale formation, being a subsurface depth of 7,934 feet, and the base of the Buda formation, being a subsurface depth of 8,150 feet, each as seen in the dual induction compensation neutron density log dated March 7, 1982, for the Energy Resources Company Walter White #8 well, API # 4248333503, located in the Jesse Pinkman Survey, Abstract 546, LaSalle County, Texas.

Where the farmout is depth-limited, and the Farmor will continue as Operator of the retained depths, the parties should consider including a Lease Maintenance and Cooperation Agreement that provides details as to their respective rights and obligations with respect to each party's operations and administration of the applicable oil and gas leases. Common provisions in these agreements include the following: (1) provisions detailing what notice is required to be provided to each party regarding drilling operations and production by the other; (2) notification obligations triggered by cessation of production or any other matter or cliam that could jeopardize the continued maintenance of the underlying leases; (3) covenants related to respecting the operations of the other party; (4) provisions regarding the joint use of roads; (5) obligations and rights wih respcct to any wells proposed to be plugged and abandoned by either party; and (6) provisions regarding renewals and extensions of leases.

In addition, if the Farmee will be drilling through shallow rights that the Farmor believes could potentially be prospective for hydrocarbon production, the Farmor may want to negotiate for a Logging Agreement requiring the Farmee, upon request by the Farmor, to run well logs across certain designated shallow intervals in wells drilled by the Farmee.

C. Carried Working Interests

In addition to describing the total number of wells or total dollar amount covered by the carried working interest, the parties should make sure to properly agree on and describe both the extent of the carry on a particular well and the various costs covered by the carry.

There are multiple points during the drilling of a well at which the parties can agree the carry should end and the Farmor should start bearing responsibility for costs attributable to its retained working interest. For example, the parties may agree that the carry ends when a well reaches casing point, or that it should extend through the commencement of the flow of production into the tanks, or even further. In order to avoid disputes over the extent of the carry, the parties should discuss the carry and ensure there has been a meeting of the minds when drafting the farmout agreement by defining the exact point at which the carry should end on a given well. Likewise, the parties should spell out what specific types of costs are (or are not) covered by the carry. While some costs are easy to classify, others may lead to disputes if not properly addressed. By way of example, a Farmor may argue that costs related to various activities, such as testing, title opinions, disposal of frac fluids, wellhead equipment and tubing, surface equipment and facilities, or construction of gathering and flow lines should be covered by the carry, but a Farmee might believe such costs fall outside the scope of standard drilling costs and therefore are chargeable to the Farmor during the course of operations. The parties may even agree that some costs that might not occur until after production has begun (such as disposal of frac fluids and costs of hydraulic lift) will still be subject to the carry.

Sometimes, ancillary agreements can affect the determination of the point at which the carry should end (and/or the point at which the Farmee has satisfied the applicable earning requirements). Parties should take into account any unique circumstances affecting operations in the prospect area, including lease obligations and third party contractual provisions, when discussing earning and carry requirements. For example, if an Operator is obligated to drill a well to certain specified requirements under a prior agreement, but encounters difficulty meeting those requirements, it may bring in a Farmee to fulfill its contractual obligations under the prior agreement. In such a circumstance, the Farmor should ensure that both the earning trigger and the carried working interest are tied to the obligations under the prior agreement so all costs of drilling the wells can be borne by the Farmee until the wells meet the specifications set forth in the prior agreement.[8]

To address possible conflicts regarding the carried working interest, parties should take care to describe and define the end of the carry with clarity and specificity. As an example, consider a farmout agreement in which the parties agree that the carry on a well should end upon "completion." In this case, the parties should define "completion" in sufficient detail to avoid ambiguity. For example, the parties may choose a definition similar to the following:

> "Complete", "Completion", or "Completed" means (a) for a well capable of producing, the point at which drilling operations have been completed, all well production facilities have been installed on the unit to enable such well to be placed on production under normal operations, and sales of petroleum (either oil or gas) have begun to be made through such surface facilities; and (b) for an unsuccessful well (*e.g.*, dry or abandoned and plugged hole or a well incapable of producing in paying quantities), that all operations in respect of the well (including for its plugging and abandonment) have been completed. Notwithstanding the foregoing, if a horizontal well has been fracced in multiple stages but is placed on production before all plugs separating the completed stages have been drilled out, then, if further operations to drill out the remaining plugs have not yet commenced within ninety (90) days after initial production from such well, then the well shall be deemed to be "Completed" retroactive as of the date the well was placed on production and any subsequent operations to drill out the plugs shall be treated as workover/rework operations under Article VI.B

[8] The terms of prior agreements may affect various other provisions of a joint venture agreement as well (such as the continuous drilling provisions or the area of mutual interest, which are discussed in more detail below in Sections II.D and IV). Drafters should ensure that the provisions of a new joint venture agreement do not conflict with obligations under prior agreements.

> (“Subsequent Operations”) of the JOA, subject to all of the proposal and voting requirements under relevant provisions for such types of “Subsequent Operations” (as defined in the JOA), and costs will be borne on a heads-up basis. If further operations have commenced to drill out the remaining plugs for the remaining frac stages within ninety (90) days after initial production from such well, such operations will be considered a continuation of Completion operations, subject to any relevant carry obligations.

Because carry obligations differ based on the specific circumstances driving various transactions, there is no single definition that will suit all agreements. Instead, parties should scrutinize their definitions to make sure they accurately reflect the parties’ understanding of how operations will be conducted and costs will be borne. For instance, the above example contemplates a carry that will end when a well is “Completed.” Moreover, it provides that “Completion” requires the installation of production facilities and commencement of hydrocarbons sales – activities that a party may not otherwise consider pre-completion operations if not expressly stated. The last two sentences of the provision specifically address horizontal wells that will be fracced in multiple stages, and provide a method for determining whether a well has been completed if it is brought to production before all of the frac stages are complete. By establishing a clear procedure for determining the end of the carry, the parties can preclude the possibility of a dispute after operations begin.

Having described the end of the carry obligation on a well with specificity, the parties should then define the costs covered by the carry. In the foregoing example, because the carry ends upon “Completion,” one option is to create a defined term for “Costs through Completion” similar to the following:

> “Costs through Completion” means all actual costs and expenses of drilling a Commitment Well through Completion, including all of the following costs to the extent and only to the extent the same are incurred on or before Completion: all costs associated with the drilling of a Commitment Well that are chargeable to the joint account under the JOA and any third party title review or examination costs; permitting costs; drilling and completion costs; costs for any on-lease facilities (including separation equipment and metering equipment) that are required to enable sales of hydrocarbons from the Commitment Well; and if any Commitment Well is not capable of producing in paying quantities, then the costs of plugging and abandonment, restoration, and reclamation required by Applicable Law or contract and decommissioning and dismantling costs associated with such unsuccessful Commitment Well.

The above examples represent merely a few of the possible ways to structure a drilling carry. Regardless of the method used to define the scope of the carry, the farmout agreement should be clear and specific both as to covered costs and, if applicable, the time at which the carry ends. Even in agreements that base the carry on a dollar cap rather than a number of wells, it remains important to properly describe those costs that count toward the dollar cap.

D. Continuous Drilling Operations and Earning Wells

When a farmout provides for the drilling of multiple wells, the agreement should also set forth the number of wells to be drilled, the timing for such wells, and the acreage to be earned after meeting the drilling requirements.

In describing the timing of the Farmee's drilling obligations, the parties should indicate whether actual commencement of drilling activities must begin by a given deadline, or whether the Farmee merely needs to begin conducting operations in preparation for drilling. Likewise, the parties should set forth whether a well must be completed by a certain deadline. If the primary terms of leases within the prospect area are nearing expiration, then the Farmee's drilling operations should factor in such deadlines. The timing requirements in a multi-well farmout should also address the amount of time allowed between wells, and specifically describe the triggering event that starts the clock on the next well (*e.g.*, the date the rig is released on the previous well, or the date the previous well reaches casing point, or is completed). A Farmee may also want the flexibility to "bank" time if it drills a well earlier than its deadline so that it may take more time between subsequent wells, if necessary.

The parties should also decide whether drilling requirements are subject to *force majeure*, and if so, they should carefully describe the scope and effect of any *force majeure* event. In some cases, if all or substantially all of the farmout acreage is covered by one lease, then the continuous drilling and *force majeure* provisions may be easily drafted by reference to those contained in the underlying lease. If not, then such provisions may need to be separately written into the farmout agreement. In any case, the parties should ensure that the continuous drilling requirements in the farmout agreement are at least as stringent as those contained in the underlying leases, in order to prevent the loss of acreage resulting from the failure to comply with lease drilling requirements.

In addition to describing the timing requirements, the farmout agreement should set forth the requirements for a well to qualify as an "earning well" that satisfies the Farmee's drilling obligations and entitles the Farmee to earn acreage in the prospect area. As a preliminary requirement for a well to qualify as an earning well, the parties should describe the objective depth to which a well must be drilled. Such a provision should be as specific as possible. For example:

> Unless otherwise agreed to in writing by the Parties: (a) all wells drilled hereunder … shall be drilled horizontally, meaning drilled in a manner whereby the horizontal component of the completion interval in the "Haynesville Zone", as defined for the Saul Goodman Field in Office of Conservation Order No. 405-H, exceeds (i) the vertical component of such completion interval and (ii) a minimum of three thousand feet (3,000') in the Haynesville Zone; and (b) shall be drilled by Farmee with due diligence, in a workmanlike manner, in accordance with good oilfield practice, and in compliance with applicable laws and regulations to such depth that, in Farmee's sole opinion exercised in good faith, adequately tests the Haynesville Zone (the "Objective Depth").

Once the objective depth has been described, the parties can follow by defining which wells will constitute earning wells:

> For purposes of this Agreement, an "Earning Well" shall mean a timely commenced Initial Unit Well that reaches total depth. An Earning Well shall be deemed to have reached "total depth" for purposes of this Agreement when it has been drilled to the Objective Depth and the horizontal component of the wellbore has been drilled to the permitted horizontal displacement.

In some cases, the parties may decide that the objective depth should not be a firm obligation, and that the Farmee should be given some leeway to drill a well as an earning well if if the objective depth cannot be reached but the well can still be completed as a producing well. The parties can provide the Farmee with the requisite flexibility by appending the definition of Earning Well with a qualification such as follows:

> For purposes of this Agreement, an "Earning Well" shall mean a timely commenced Initial Unit Well that reaches total depth. An Earning Well shall be deemed to have reached "total depth" for purposes of this Agreement when it has been drilled to the Objective Depth and the horizontal component of the wellbore has been drilled to the permitted horizontal displacement, *or to such shorter length as may be deemed prudent, in Farmee's sole judgment exercised in good faith, to assure maintaining the integrity and utility of the wellbore, based on factors such as then-existing hole conditions, equipment limitations, geologic factors or other relevant considerations*.

The locations of the earning wells should also be addressed in the farmout agreement. The parties may consider specifically identifying the location of the initial test well, or may provide that the first few wells in the prospect area should each be drilled in a diferent pooled unit. Often, as with the timing of the Farmee's continuous drilling obligations, lease maintenance issues will drive requirements related to well locations. If certain leases within the prospect area are nearing termination before others, then the parties should prioritize the drilling of wells in the lands covered by the leases nearing termination. Additional factors related to well location include paying quantities and depletion rates. If existing wells are beyond their primary terms but are being relied upon to maintain the underlying leases, depletion of the existing wells may factor into the parties' decision as to where to drill. If a large prospect area contains multiple units, and one unit is held by a well that is approaching depletion, then it is in both parties' interest to drill a new well in that unit before those leases expire due to lack of production in paying quantities.

In a typical farmout, the Farmee will earn a portion of the acreage in the prospect area upon satisfaction of its obligation to drill an earning well. When drafting the farmout agreement, the parties should specify the percentage interest to be assigned to the Farmee, the location of the earned acreage, and the timing of the assignment. For example, if the prospect area consists of multiple pooled units, and one earning well must be drilled in each pooled unit, then the farmout agreement might provide for the Farmee to earn an undivided interest in all leases located within the pooled unit where the applicable earning well is drilled. Alternatively, the parties may provide for the Farmee to earn a given number of net acres for each earning well drilled.

Additionally, the parties may negotiate over the point at which the Farmee earns an interest in all remaining acreage. For example, if the Farmee commits to drill six earning wells, then the farmout agreement may set forth that the Farmee shall earn a certain number of net acres for each of the first five earning wells, and upon the drilling of the sixth earning well to the objective depth, the Farmee shall earn an undivided interest in all remaining leases within the prospect area that were not previously earned by the Farmee.

E. Selected Title Due Diligence Issues

1. Ensuring the Existing Contracts / Applicable Law Will Accommodate the Contemplated Development

Numerous and complex pooling, surface use, production allocation, and related land and title issues may arise when an Operator ventures to commence an unconventional drilling program from a conventional oil or gas field. A discussion of these issues is beyond the scope of this paper, but the parties to such a joint venture agreement should conduct appropriate due diligence of such issues as the following:

(a) Will the existing oil and gas leases, surface use rights, pooling agreements, and other applicable contracts, as well as any applicable regulatory law, accommodate the contemplated exploration program? If not, what contractual agreements and/or regulatory procedures are available and/or advisable to remedy the situation either before or after execution or closing of the farmout agreement?[9]

(b) If the applicable oil and gas leases are beyond their primary term but have been maintained by production, has that production been continuous and sufficient at all times to maintain the leases pursuant to their express terms and/or any applicable state law?[10]

(c) Do the applicable oil and gas leases include any partial termination provisions such as vertical or horizontal "Pugh" clauses, continuous drilling, and retained acreage provisions that could operate to have caused a termination of the leases as to any of the lands or depths within the contemplated exploration program?[11]

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[9] For recent developments of this issue (a) in Texas, for example, *see* Brian R. Sullivan, *Railroad Commission Update*, The University of Texas School of Law 41st Annual Ernest E. Smith Oil, Gas and Mineral Law Update (March 27, 2015); John R. Hays, Jr. and Alicia R. Ringuet, *Regulatory Update*, State Bar of Texas OGERL Section Report, Volume 39, Number 2 (Winter 2015); Terry E. Hogwood, *Allocation Units and Surface Owners*, State Bar of Texas OGERL Section Report, Volume 39, Number 2 (Winter 2015); Michael E. McElroy, Production Allocation: Looking for a Basis for Discrimination, State Bar of Texas OGERL Section Report, Volume 38, Number 3 (Spring 2014); (b) in Pennsylvania, *see* Michael J. Byrd, *An Analysis of the New Pennsylvania Horizontal Drilling Legislation*, Baker & McKenzie Client Alert (July 2013), discussing the 2013 legislation (Senate Bill 259) generally permitting operators to drill horizontal wells across lease lines even without pooling authority, at http://www.bakermckenzie.com/files/Uploads/Documents/Global%20EMI/al_na_horizontaldrillinglegislation_jul13.pdf ; *see also EQT Production Co. v. Opatkiewicz*, Case No. 13-013489, Court of Common Pleas of the State of Pennsylvania, County of Allegheny, which upheld the constitutionality of said 2013 legislation.

[10] *See* Michael J. Byrd, Louis J. Davis, Ben H. Welmaker, and James C. Sonnier, *Common Legal Issues in U.S. Shale Plays*, State Bar of Texas OGERL Section Report, Volume 34, Number 2 (December 2009), re-published as *Exploring Common Legal Issues in U.S. Shale Plays*, AAPL *Landman* (January/February 2010).

[11] *Id.*

2. Restrictions on Assignment

The parties to an assignment of oil and gas assets in conjunction with a joint venture agreement must comply with any applicable restrictions on assignment in the applicable oil and gas leases and contracts, such as consents to assign in the leases or other contracts, and preferential rights to purchase and maintenance-of-uniform-interest provisions in joint operating agreements. Because such restrictions on assignment are common to traditional acquisitions through purchase and sale agreements, a detailed discussion of the title and due diligence issues and law with respect to such restrictions on assignment is beyond the scope of this paper; however, to the extent that such provisions are relevant to exit strategies of the joint venture parties, the reader is referred to the additional discussion of such provisions in Article VI of this paper.[12]

III. Asset-Level Joint Ventures Where the Investor is not the Operator

As set forth above, under the typical farmout arrangement, operations of the applicable property are transferred to the Farmee. However, it has become quite common in today's market environment for a party who originally owns and operates the oil and gas assets to retain responsibility for operations but enter into a joint venture with a financial partner ("Investor") participating in a non-operating role. For ease of reference, this article will refer to these kinds of joint ventures as "Nontraditional Joint Ventures." Typical Investors in Nontraditional Joint Ventures include: (i) hedge funds, private equity groups, and similar financial institutions looking for significant upside with low cost entry points; (ii) other oil and gas companies looking to acquire interests in the particular assets at issue; (iii) foreign investors and companies looking to make investments in US oil and gas assets; (iv) foreign investors and companies looking to acquire expertise with respect to unconventional oil and gas operations; and (v) liquefied natural gas ("LNG") exporters/importers seeking to acquire a direct interest in a source of supply.

A. Drill-to-Earn Structure

1. Basic Structure

Similar to farmout agreements, many Nontraditional Joint Ventures provide for the Investor to acquire an interest in the oil and gas properties only when a well is drilled. Also similar to farmout agreements, these transactions typically include a carried interest component in which the acquiring party pays a portion of the divesting party's drilling costs in exchange for the rights to participate in the wells and to acquire designated leasehold acreage. Unlike farmout agreements, however, the divesting party retains operations.

These structures generally impose some minimum commitment on the Investor to fund the new drilling program ("Drilling Commitment"). For example, the Investor may be required to participate in the drilling of a certain number of wells in order to earn the acreage. Alternatively, the Drilling Commitment may be a specified dollar amount. If the Investor fails to

[12] For an excellent and detailed analysis of these issues, *see* Terry I. Cross, *The Ties That Bind: Preemptive Rights and Restraints on Alienation That Commonly Burden Oil and Gas Properties*, 5 Tex. Wesleyan L. Rev. 193 (1999).

satisfy the Drilling Commitment, it will usually only earn an interest in those completed wellbores for which it satisfied its carry obligations.

The following hypothetical terms illustrate a basic example of such a structure:

(a) The Operator and the Investor agree to a Joint Exploration and Development Agreement. Each year, the Operator will propose, and the Investor will approve, the wells to be drilled and a development budget.

(b) The Investor will fund 100% of the drilling costs and be assigned an 85% working interest in each well (with the Operator retaining a 15% carried working interest). Upon the Investor achieving a 15% IRR on its annual investment, the Investor's interest in the wells drilled in that year will be reduced to 15% and the Operator's interest will be increased to 85%.[13]

(c) The agreement shall continue for 5 years or until the Investor has spent $500 million on development costs.

2. Common Drivers

In today's environment, the fact that this kind of structure does not add debt on the Operator's financial statement can be a significant advantage to many Operators. The structure also allows Operators to continue with their drilling programs at a time when many companies have greatly reduced their capital expenditure budgets due to commodity price decreases, balance sheet concerns, etc. Continuing the drilling program may be essential to lease maintenance and/or express or implied development or lease protection covenants, or to support existing midstream commitments. Moreover, the large amount of available private capital eager to invest in energy at a time of low prices provides leverage to the Operator to negotiate favorable deal terms. In addition, for some public companies, a high profile drilling fund commitment with a well-regarded Wall Street Investor may help boost share prices (whereas, by contrast, a new equity raise to obtain drilling capital may dilute the existing shares.)

For the Investor, these joint ventures can offer the opportunity to team up with premier management teams and participate in the significant potential upsides of successful drilling programs. Notwithstanding the competition of other private capital sources, the depressed commodity price environment still provides many Investors with sufficient leverage to negotiate deals with attractive risk-adjusted return potential.

3. Negotiating Points

Common issues with the drilling fund structure include the following:

(a) Development plan. [14]

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[13] In some variations – for example, when the drilling program covers multiple, diverse plays and/or where the deal includes a substantial Drilling Commitment, the working interests of the Investor may vary among different areas covered by the joint venture. Other variations include adjustment mechanisms that are tied to future commodity prices, as discussed below in Section VII.A.

Investors who agree to make a large and/or long-term Drilling Commitment will want to have considerable input into the development plan. Often, an initial development plan is agreed to upfront and incorporated into the primary formal joint development agreement. If the agreement contemplates subsequent development plans, the parties will need to address the process for proposal and approval of the plan, and what happens if the parties fail to agree on the subsequent plan.

(b) Remedies to the Operator for the Investor's failure to fund.

The Operator will want adequate assurances that the Investor will fulfill its Drilling Commitment. Possible alternatives include advance funding requirements (escrowed or otherwise)[15], specific performance, liquidated damages, early termination rights, and forfeiture of previously earned interests.

(c) Limitations on the Investor's liability for cost overruns.

(d) Limitations on or exclusions from the Drilling Commitment obligation (such as non-operated wells).

(e) Limitations on the Operator entering into other drilling joint ventures within a negotiated area of interest.

(f) Other business terms such as additional consideration between the parties (for example, a management fee to the Operator or a commitment fee to the Investor).

B. Acquisition Joint Ventures

In addition to the Investor providing capital for drilling, some joint ventures with similar structures (such as the recently announced acquisition alliance between LINN Energy, LLC ("LINN") and Quantum Energy Partners ("QEP")) include funding for future acquisitions. According to publicly disclosed information, the basic structure of the LINN-QEP alliance includes the following terms:

1. Initial commitment by QEP of up to $1 billion to a newly-formed LLC ("AcqCo") to fund future acquisitions and development.

2. QEP will initially own 100% of AcqCo. and will have 3 of 5 board seats. LINN will have the right to participate for as little as 15% or as much as 50% in any acquisitions by AcqCo and receive a corresponding working interest.

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[14] *See* also Section III.B below.

[15] Note, however, that advance funding by the Investor will delay the achievement of the Investor's return hurdle and thereby delay the occurrence of the interest reversion.

3. LINN will provide management services and be reimbursed for G&A, and will have the ability to earn an undisclosed promoted interest in AcqCo. after QEP achieves an undisclosed return target on its investment.

4. LINN will have a right of first offer[16] on any asset divestitures proposed by AcqCo.[17]

The LINN-QEP alliance came on the heels of a December, 2014 letter of intent for a $500 million, five-year drilling fund joint venture between LINN and GSO Capital Partners, a unit of Blackstone Group LP.[18]

C. Cash and Carry Structure

In another common structure, the Investor receives an up-front assignment of its undivided interest in all of the relevant oil and gas assets. Similar to typical farmout transactions, the consideration under this structure usually includes both cash, upon the execution of the underlying transaction documents or at closing, and – similar to both farmouts and the drilling fund structure discussed above, the obligation by the Investor to pay a certain amount of the costs attributable to the Operator's retained working interest for an agreed number of wells or up to an agreed dollar amount (the "Carry Consideration"). Transactions in which the consideration includes both cash upfront and a Carry Consideration are often referred to as "Cash and Carry" transactions.

Last fall's Woodford Shale joint venture between Continental Resources, Inc. ("CLR"), and SK E&S Co., Ltd. ("SK") is a publicly-disclosed example of this type of structure. Under the basic terms of this transaction, SK acquired an undivided 49.9% interest in CLR's Woodford Shale assets for $90 million at closing, plus a carry obligation capped at $270 million to cover 50% of CLR's future drilling costs over a five-year term.

D. Timing of Assignment; Default and Security Provisions

An important term of a Nontraditional Joint Venture concerns the timing of the record title assignment to the Investor of its undivided interest in the transaction assets. At one end of the spectrum, if a material portion of the consideration is paid in cash at closing, the Investor will usually insist on receiving an assignment at closing of the Investor's undivided interest in all of the transaction assets – specifically all of the leasehold and any existing wells that are included in the transaction. In this scenario, the prudent Operator will negotiate for terms that provide security for the Carry Consideration, since this is an amount to be paid by the Investor over time. The security provisions are often heavily negotiated. Common security alternatives include: (i) liens and security interests covering the Investor's interest pursuant to a joint operating agreement ("JOA"), or otherwise (such as the standard operator's lien in the Model Form JOA, or an enhanced version thereof); (ii) mortgages on the Investor's working interest; (iii) re-

[16] *See* Article VI below for further discussion on rights of first offer and similar preemptive rights.

[17] *See* Linn Energy news release dated March 24, 2015, at http://ir.linnenergy.com/releasedetail.cfm?ReleaseID=903003

[18] See Linn Energy news release dated January 2, 2015, at http://ir.linnenergy.com/releasedetail.cfm?ReleaseID=889240

assignment obligations; (iv) letters-of-credit/performance bonds; (v) an obligation by the Investor to make advance payments for estimated development expenditures (such as on a monthly or quarterly basis); and (vi) parent guaranties (which may or may not be capped). Since Investors in Nontraditional Joint Ventures are not always industry players, but rather, investors on the financial side that may desire to attract other investors to participate in the applicable investment-vehicle, the Operator's need for security often must be balanced against the Investor's ability to attract additional investment.

At the other end of the spectrum, many pure drilling fund joint ventures provide for no cash upfront, but only obligate the Investor to fund the Drilling Commitment. When this structure is used, the parties may negotiate over how much the Investor will earn and when the earned interest will be assigned. For example, in some deals, the Operator may propose that the Investor will only earn individual wellbore assignments each time the Investor has fully funded its carry obligation on a new well.

E. Development Plans and Budgets

Nontraditional Joint Venture arrangements will typically contain an initial development plan (of some specified time) and a corresponding budget, which are intended (at a minimum) to facilitate the full utilization of the Carry Consideration. The key components are illustrated in the following example:

> Prior to signing the definitive agreement, Operator will prepare and provide to Investor an initial 48-month budget for Investor's prior approval (the "Initial Budget"), which will provide that (a) the Drilling Carry costs that Investor will be required to pay during each of the first two years of the Carry Period will not be less than $100,000,000 (subject, however, to Operator's rights to carry over to subsequent year(s) any Drilling Carry amounts that have not been expended and that are below this $100,000,000 threshold ("Rollover Amounts")), (b) for year three of the Carry Period, the Drilling Carry costs that Investor will be required to pay will not exceed the amount obtained by taking the remaining Drilling Carry amount at the beginning of such year (taking into account any Rollover Amounts) and dividing that amount by 2, and (c) during year four of the Carry Period, the Drilling Carry costs that Investor will be required to pay will be any remaining Drilling Carry costs.

To ensure timely development, Investors will often push to have any unused Carry Consideration forfeited at the end of the applicable drilling carry period. Negotiating such a provision helps to incentivize the Operator to develop the JV assets rather than other drilling opportunities within its portfolio, knowing that it only has a finite amount of time to enjoy the benefit of having some or all of its costs carried by the Investor.

Given the nature of proposed development plans and budgets, the underlying transaction documents should be drafted so that there is sufficient flexibility for the parties to modify the development plan and corresponding budget if needed (as they are merely estimates made without the knowledge of potential subsequent factors that may change, such as market economics, technological advances, and geological discoveries) to ensure that the parties have a reasonable expectation of receiving the benefit of their bargain. Additionally, there is often an inherent tension between Investors and Operators as to development plans and budgets, as each may have a different economic objective. For example, in a joint venture between a domestic Operator and a foreign Investor looking to import LNG from the U.S., the Investor's objective would be to ensure a sufficient source of gas supply to meet its long-term export strategy, while the Operator's primary objective may be to hold acreage and leases with minimum costs during times of depressed gas prices. Under such a scenario, the agreed Development Plan might be designed to balance the following factors and objectives: (a) the Investor's needs for steady and long-term gas production to ensure a sufficient source of gas to meet its export strategy, (b) the Operator's need to hold existing leases and acquire new acreage, and (c) ensuring the full utilization of the Drilling Carry.

Operators will want some discretion to deviate from and amend the applicable budget. A key negotiation point between Investors and Operators is the Operator's unilateral authority to deviate from the budget. The agreement may provide, for example, that the Operator shall consult with the Investor with respect to any material changes in the Development Plan, and if and when the Operator becomes aware that expenditures will be more than a specified percentage over budget in a given year, the Operator must submit a supplemental or amended budget that reflects such variance for the Investor's prior approval.

As for operations that are specifically provided for in the approved development plan (or in any subsequently approved budgets), the Operator will want to provide that the Investor may not go non-consent in any such operations until the entirety of the Carry Consideration has been spent.

Some Nontraditional Joint Venture arrangements will call for an operating committee (sometimes called a management committee) to review, approve, and modify development plans and budgets. While it is typical for Investors to have some influence on the operating committee, usually (but not always), the Operator will have the controlling vote.

F. Secondment

The use of secondment arrangements, while common in the international oil and gas context, are fairly atypical in U.S. oil and gas transactions. Investors (particularly foreign investors looking to acquire expertise with respect to unconventional oil and gas operations) often seek secondment arrangements with the Operator so that the Investor's employees may observe and participate in joint operations.[19] If the parties agree to utilize a secondment arrangement, they should, at a minimum, address the following issues: (i) who will pay the secondee while the secondee is working with the Operator; (ii) what will be the extent and scope of the secondee's activities while with the Operator (this point is often based on whether the secondment arrangement is provided merely as an accommodation to the Investor or the secondee will actually be doing valuable work for the Operator); (iii) how many secondees may the Investor send at one time, and can they be replaced; and (iv) can the Operator terminate the

[19] In documenting the secondment arrangement, note that the AIPN has a model form Secondment Agreement that may be beneficial to use either as a starting point or for comparison purposes. *See* 2002 AIPN Model Secondment Agreement.

secondment arrangement if there is a change in control of the Investor. The issue noted in (iv) of the preceding sentence can be critically important for Operators, particularly in the context of an Investor being acquired by a competing operator in the area. In that scenario, the Operator is at risk of the competing operator having the ability to send a secondee to observe the Operator's activities.

A common compromise to the formal secondment arrangement is for parties to agree upon a more informal training program. For example, a training program may be structured to include the following: (i) at least one quarterly in-person meeting/program to be held at the Operator's offices principally designed to provide technical and operational training with respect to the applicable assets to certain of the Investor's representatives; (ii) at least one monthly conference call hosted by the Operator so that representatives of the parties may discuss the status of development operations and any operating reports or other data that may have been distributed by the Operator; and (iii) at least one weekly, informal conference call hosted by the Operator so that the parties may discuss any follow-up issues pertaining to the applicable assets. If informal training programs are used in place of formal secondment arrangements, the parties should ensure that the mutually agreed informal arrangements are fully understood by both parties and clearly set forth in the definitive transaction documents.

IV. Entity Level JV's

In addition to asset-level structures, some joint ventures call for an entity-level structure in which the Operator and the Investor form a new entity ("Newco"), which directly owns the entirety of the joint venture assets. Generally, the Operator will form and primarily manage Newco and contribute the oil and gas assets to Newco, while the Investor will agree to a Carry Consideration and, often, will contribute some upfront cash to Newco. Rather than an asset acquisition agreement, this type of structure is typically documented with a Contribution Agreement, an LLC Agreement (or similar corporate equivalent), and a joint operating agreement.

One advantage of an entity-level joint venture is that it will generally not trigger preferential rights to purchase (which are further discussed below in Section VI.A), consents to assign, or other restrictions on transfer.

V. AMI Issues

Under a standard area of mutual interest ("AMI")[20] provision, the parties agree to offer each other a proportionate share of any newly acquired leases, as well as other interests within a defined area. An AMI is essentially an option agreement – a continuing offer that becomes a bilateral contract only once an interest is offered to and accepted by another party pursuant to the terms of the AMI provision.[21] The following is a typical example:

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[20] The term "AMI" is colloquially used to refer to both (i) the geographic area subject to the agreement and (ii) the AMI agreement itself. AMI provisions are commonly included within broader joint venture contracts, such as operating, farmout, exploration, and participation agreements.

[21] *Courseview, Inc. v. Philips Petroleum Co.*, 312 S.W.2d 197, 207 (Tex. 1968).

Area of Mutual Interest. The Parties agree that, (a) the Prospect Area, plus (b) all lands within one-half (1/2) mile of the perimeter of the Prospect Area, shall constitute an Area of Mutual Interest ("AMI") which shall remain in effect for a period of three (3) years from the date on which total measured depth is reached in the Initial Earning Well, unless extended; *provided, however*, if this Agreement is terminated by the mutual agreement of the Parties, then the AMI shall also terminate at the same time.

AMI provisions must be drafted carefully. Because the provision is governed by the terms set forth in the applicable contract, a court's interpretation of the AMI provision will be restricted to its express language.[22] Judicial interpretation will only be supplemented by extrinsic evidence when the contract language is ambiguous.[23]

Often, contracting parties will not have leased all of the areas to be explored or developed before executing an agreement to jointly develop a prospect area. The AMI provision will therefore assist in: (i) assuring that each party has the right to maintain its relative position in the project in relation to the other parties; (ii) reducing the parties' competition for future acquisitions because any acquisition of interests in the prospect area must be offered proportionally to the other parties; (iii) reducing acquisition costs because parties may no longer need to rush to purchase leases in an attempt to gain a competitive advantage; and (iv) improving the parties' willingness to expend funds on seismic surveys or other exploratory costs, as they know they will have the option of sharing in any acquisitions within the AMI area.[24]

A. Negotiating and Drafting an AMI Provision

1. Defining the AMI and the Statute of Frauds

Because joint venture contracts employing AMI provisions typically involve the transfer of real property interests such as leases or mineral interests, these agreements are governed by the statute of frauds.[25] The statute of frauds has been held to apply to mineral leases[26] and options to acquire oil and gas leases.[27]

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[22] Gerald F. Slattery, Jr. & Amanda Davis Landry, *Understanding Area of Mutual Interest, Preferential Rights and Maintenance of Uniform Interest Provisions in Joint Operating Agreements*, 56 ANN. INST. ON MIN. L. 323, 332 (2009).

[23] *See Kincaid v. Western Operating Co.*, 890 P.2d 249, 252 (Colo. App. Ct. 1994) (noting that, "[i]f there is an ambiguity as to the terms of a contract, extrinsic evidence is admissible to prove the intent of the parties to that contract").

[24] Slattery & Landry, *supra* note 22, at 327–28.

[25] Agreements to assign interests in oil and gas leasehold estates are subject to the Statute of Frauds. *Westland Oil Dev. Corp. v. Gulf Oil Corp.*, 637 S.W.2d 903, 908–09 (Tex. 1982). *But see Palmer v. Fuqua*, 641 F.2d 1146 (5th Cir. 1981) (showing a willingness to avoid invalidating an AMI under the statute of frauds although acknowledging that the statute of frauds applies to oil and gas leases); *see also* Matthew A. Thanheiser & David W. Wallace, *Areas of Mutual Interest*, 16 St. Sec. R. Oil Gas & Energy L. 9, at 3 (December, 1991).

[26] *See generally Shaller v. Allen*, 278 S.W. 873 (Tex. Civ. App.—Amarillo 1925, no writ).

[27] *See generally Stekoll Petroleum Co. v. Hamilton*, 152 Tex. 182 (1953).

To satisfy the statute of frauds, the property description in the AMI provision must furnish within itself, or by reference to some other existing writing, the means or data by which the AMI area may be identified with reasonable certainty.[28] In most states, a land description using a reference to a different agreement, map, or plat is adequate so long as that description is sufficiently certain. In Texas, for example, in *Westland Oil Dev. Corp. v. Gulf Oil Corp.*, a letter agreement attempted to establish an AMI by describing the lands by reference to an ancillary farmout agreement:

> If any of the parties hereto… acquire [*sic*] any additional leasehold interests affecting any of the lands covered by said farmout agreement, *or any additional interest from Mobil Oil Corporation under lands in the area of the farmout acreage*, such shall be subject to the terms and provisions of this agreement.[29]

The Texas Supreme Court determined that the words "said farmout" in the first clause were sufficient to satisfy the statute of frauds because another paragraph in the letter agreement defined "said farmout," specifically directing the reader to an agreement which provided a legally sufficient description of the AMI.[30] However, the second clause (italicized above) failed to satisfy the statute of frauds because "lands in the area" was not a legally sufficient description.[31] In particular, the court opined that "the description necessary to meet the requirements of the statute of frauds cannot be arrived at from tenuous inferences and presumptions of doubtful validity."[32] If extrinsic evidence must be used to resolve an ambiguity in an instrument, such evidence may only be used insofar as it draws from the text within the instrument.[33]

When drafting an AMI provision, the area and depths that will be subject to the AMI must be carefully described. In general, using an exhibit that meticulously describes the covered area is good practice. For such purpose, parties typically include in the exhibit a plat that outlines the AMI area. If parties define the geographic boundaries only by shading an outline on a plat, ambiguities may arise if the boundaries of the prospect area do not lie along survey or tract lines. Such ambiguities may create a question as to whether the description of the AMI area satisfies the statute of frauds.[34] Where the boundaries of the AMI set forth in the plat do not lie along survey or tract lines and only a portion of the tract or survey is included within the AMI area, it is good practice to include a specific provision addressing whether the AMI area will be deemed to include only such portion of the tract or survey or all of the tract or survey.[35]

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[28]*See Long Trusts v. Griffin*, 222 S.W.3d 412, 416 (Tex. 2006); *see also supra* note 6.

[29] *Id.* at 905 (emphasis added).

[30] *Id.* at 909. *See also U.S. Enterprises, Inc. v. Dauley*, 535 S.W.2d 623 (Tex. 1976) (holding that a writing can provide sufficient description by referencing another document).

[31] *Westland*, 637 S.W.2d at 909.

[32] *Id.* at 909–10 (citing *Rowson v. Rowson*, 154 Tex. 216, 275 S.W.2d 468 (1955); *Wilson v. Fisher*, 144 Tex. 53, 188 S.W.2d 150 (1945)).

[33] *Id.* at 910.

[34] *Id.* See also *Heirs and Unknown Heirs of Barrow v. Champion Paper & Fibre Company*, 327 S.W.2d 338 (Tex. Civ. App.—Beaumont 1959, writ ref'd n.r.e.) and *U.S. Enterprises, Inc. v. Dauley*, 535 S.W.2d 623 (Tex. 1976) for cases suggesting that reliance upon ambiguous maps may fail to satisfy the statute of frauds.

If parties are concerned that an AMI description may not be sufficiently certain, it is advisable to include a "catch-all" or "savings" clause to ensure that the AMI is enforceable at least insofar as it covers those lands that clearly lie within the AMI.[36]

2. The AMI Trigger

The triggering event of the AMI obligation typically comprises the following elements: (a) an acquisition (b) by a party (c) of an acquired interest (d) within the AMI term. The "acquisition" element typically includes (i) a direct or indirect acquisition of an acquired interest within the AMI, (ii) a proposed acquisition of such acquired interest, or (iii) a direct or indirect acquisition of an option or right to acquire such acquired interest. The definition of "party" is typically expansive and includes the parties to the agreement and all related parties and affiliates. The "acquired interest" element is a central point of negotiation, as it can significantly expand or restrict the scope of the AMI obligations.[37] Parties should also establish a term for the survival of the AMI to prevent a potential violation of the rule against perpetuities in certain jurisdictions[38] and to limit its effects to within the anticipated period of time contemplated by the parties for the particular venture. Negotiating termination events must also be carefully

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[35] *E.g.*, (i) "To the extent the boundaries of the lands outlined on Exhibit 'B' do not lie on or along survey, section, or other governmental tract lines, the Parties intend to include partial surveys, sections, or governmental tracts in the AMI," or (ii) "It is the intent of the parties hereto that the heavy dark lines highlighted in yellow lie on survey, section, or other governmental tract lines, and that no partial surveys, sections or governmental tracts be included in the AMI. If any portion of the survey is within the dark line, then all of that survey is within the AMI."

[36] *E.g.,* "If for any reason it is or becomes unclear as to whether any tract of land lies within the area covered by the AMI, the Parties intend the AMI to be effective with respect to any and all lands clearly within the outlined area."

[37] Parties may elect to include a broad or narrow definition of the term "acquired interest"; *e.g.,* "any lease, mineral interest, royalty interest, overriding royalty interest, or renewal or extension thereof covering lands within the AMI"; or "any oil and gas leasehold interest (including any renewal, modification, amendment, or extension of same); or any other interest in the oil, gas and mineral estate, including any working interests, operating or non-operating rights, fee mineral interests, production payments, net revenue or net profits interests, carried interests, royalty interests, overriding royalty interests, and any other interest in oil and gas rights, or rights to earn or acquire any such interest under a farmout/farmin contract, farmout option contract, or any other right to explore for, drill for, develop, produce, exploit, store, dispose of, process, compress, separate, transport, market, or distribute oil or gas or other associated hydrocarbons; or any other right or interest in any treatment and processing plant, equipment, machinery, fixtures, facilities, flow lines, pipelines, gathering lines, easement, permits, licenses, servitudes, rights of way, surface leases, salt water disposal well, injection well, water well, and other surface rights, and other tangible personal property or improvements, located in or on the AMI, or used or held for use in connection with the operations of any of the rights or interests described above; or any other option or right to acquire any of the foregoing."

[38] The rule against perpetuities has been held applicable to oil and gas leases. *Nantt v. Puckett Energy Company*, 382 N.W.2d 655, 659–60 (N.D. 1986). However many courts have expressed an uneasiness against invalidating mineral leases under the rule. *See* Lansdown, *Golden v. SM Energy Company and the Question of Whether an Area of Mutual Interest Covering Oil and Gas Rights is Binding on Successors and Assigns*, 89 N.D. L. REV. 267, 279–-81 (2013) (for a discussion on the tendency for courts to uphold the intent of the parties when interpreting mineral leases). For example, the Kansas Supreme Court held that an AMI agreement does "not involve the vesting of future interests in real property and [therefore does] not constitute a restraint upon the alienation of that property." *First National Bank & Trust Company v. Sidwell Corporation*, 678 P.2d 118, 126–27 (Kan. 1984). *See also Courseview, Inc. v. Phillips Petroleum Co.*, 258 S.W.2d 391 (Tex. Civ. App.—Galveston 1953, write ref'd n.r.e.) (holding that an AMI agreement does not create a right in any real property).

considered (including whether the AMI is to terminate upon termination of the applicable underlying agreement).

3. The AMI Offer and Election

The parties should include a procedure for offering and electing to participate in the acquired interest. Generally, the acquiring party will provide an offer to the non-acquiring parties of a pre-agreed upon percentage of the acquired interest and the non-acquiring parties are allowed a certain period of time to make their acquisition election.[39] Ideally, the AMI offer should contain information reasonably necessary for a buyer to make an informed decision. AMI provisions typically require the offer to include: (i) copies of the conveyance instrument(s) vesting the acquiring party with ownership of the acquired interest; (ii) a description of all burdens and obligations related to or affecting the acquired interest, and, if the acquired interest is subject to other agreements, copies of those agreements; and (iii) copies of all checks, drafts, and similar type instruments, given, or to be given, by the acquiring party as consideration for acquisition of the acquired interest, together with copies of all invoices for actual out-of-pocket costs incurred by the acquiring party that are directly related to acquisition of the acquired interest. The procedure for the offer and election to participate in an acquired interest should be negotiated and described in detail, including defining deadlines for responding to an AMI offer and consequences for the failure to respond.[40] Specified sensitive matters (such as drilling operations in or near the area bring acquired) may require a shorter deadline.[41] If there are multiple related parties, consider whether to name a representative for such parties in order to expedite the notification and election process.

The AMI provision should carefully set forth the percentage of the acquired interest each party is entitled to acquire. The percentage may either be fixed or variable, for example, dependent upon the actual working interest of the parties in the prospect area at the time of the triggering event. Moreover, the instrument should specify the course of action if a party declines the offer – that is, whether participating parties are entitled to take their proportionate share of the declined interests, whether the acquiring party should re-offer the declined interest to the remaining parties, etc. If no specific provision detailing a declined offer exists, the acquiring party may be entitled to retain the declined interests. In *Cyanostar Energy Inc. v. Chesapeake Exploration LLC*, an Oklahoma court held that, unless the AMI provision expressly provides that the acquiring party has to re-offer the declined interests to the remaining parties, the acquiring party is entitled to retain such declined interests.[42]

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[39] *E.g.*, "The acquiring Farmor shall notify Farmee in writing, within fifteen (15) days after such acquisition or proposed acquisition, and offer seventy percent (70%) of the Acquired Interest, except for the reserved formation, within the AMI, to Farmee. Farmee shall then have a period of fifteen (15) days from receipt of such written notification to elect whether or not to participate in such acquisition, INSOFAR AS the acquired interest includes lands within the AMI and depths within the Prospect Interval."

[40] *E.g.*, "The non-acquiring party shall, not later than thirty (30) days after receipt of such notice from the acquiring party, notify the acquiring party, in writing, whether it wishes to participate in such acquisition. Failure of a non-acquiring party to respond within the time and in the manner provided herein to the acquiring party's notice shall be deemed to be an election not to participate in such acquisition."

[41] *E.g.* "If there is a well drilling within a one-third (1/3) mile radius of any portion of the acquired interest, then the acquiring party's notice shall so specify and the non-acquiring party shall advise the acquiring party of its election not later than seventy-two (72) hours following the non-acquiring party's receipt of the acquiring party's notice."

In general, by electing to participate, each party to an AMI obligates itself to acquire its AMI percentage and pay its proportionate share of the acquisition costs. Mechanically, the acquiring party usually first takes title to the interest and later conveys the respective shares to the electing parties. The acquiring party is not permitted to create additional burdens on any interest prior to the assignment. The non-acquiring parties often have to elect whether to participate in *all* of the property being acquired, not being permitted to select partial portions thereof. Moreover, it is important to consider the mechanics of acquiring interests covering lands that fall both inside and outside of the AMI boundaries, and how acquisition costs will be split if such an acquisition occurs.[43] In addition, the AMI provision should set forth that a party would forfeit its election to participate if such party ultimately does not pay its share of the acquisition costs.[44]

B. Special Issues – Farmouts

It is common for AMI provisions to be depth-limited. Such limitations are typically found in farmout agreements under which the Farmor reserves rights located within certain formations. In those cases, in order to protect the Farmor's reservation, (i) such reserved formations should be carved out from the standard AMI obligations, and (ii) the Farmee should offer to the Farmor 100% of the interests acquired in the reserved formation. Since an acquisition of a single lease covering both the AMI and the reserved formation would trigger both the standard AMI obligations and the obligation to offer to the Farmor 100% of the reserved formation, the parties should determine beforehand how the lease bonus and other acquisition costs will be allocated between the AMI and the reserved formation.

Another issue that arises in the context of negotiating an AMI within a farmout agreement is the treatment of unearned interests. Parties should consider whether a Farmee that fails to completely earn a contract area should forfeit its acquired interests within the unearned area. A typical structure utilized to address this issue gives the Farmor the right to acquire such unearned interests.[45] In such case, a commonly negotiated point is whether the Farmor should be able to pick and choose the unearned AMI interests it wishes to acquire, or whether it should be bound to either take all or none of the unearned AMI interests.[46]

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[42] 317 P.3d 217 (Okla.Civ.App. 2013).

[43] *See* Allen D. Cummings, *Old Area of Mutual Interest and Dedication Agreements – New Problems,* 52 RMMLF-INST 27-1 (2006) for an issues checklist regarding land spanning areas both inside and outside of an AMI area.

[44] *E.g.,* "Failure of an electing party to pay such electing party's proportionate share of the out-of-pocket cost incurred by the Acquiring Party shall be deemed an election not to participate in the Acquired Interest and a waiver of any right to do so, notwithstanding any written election to participate by that Party."

[45] *E.g.*, "If Farmee fails to drill and complete the required number of earning wells and the assignment is partially terminated pursuant to [the applicable termination provision] above, then Farmor shall have the right, but not the obligation, to acquire one hundred percent (100%) of Farmee's right, title, and interest in all acquired interests within the unearned Prospect Lands, INSOFAR and ONLY INSOFAR as they cover the unearned Prospect Lands (the "Unearned AMI Interests"). In such case, Farmee shall promptly notify Farmor, in writing, and Farmor shall then have a period of fifteen (15) business days from receipt of such written notification to elect whether or not to acquire all or part of each Unearned AMI Interest."

[46] *E.g.,* "Each Farmor shall notify Farmee in writing on or before the expiration of the fifteen (15) business day period as to whether or not such Farmor elects to acquire each Unearned AMI Interest (whether in whole or in part), and the portions of each Unearned AMI Interest such Farmor elects to acquire. If any Farmor fails to so notify

C. Other Issues and Further Considerations

If the parties agree to an AMI, but the lands subject to such AMI are also subject to a preexisting AMI among a subset of the parties, then an acquisition within the AMI may trigger rights existing under both AMI provisions. Therefore, when a party or parties are subject to a preexisting AMI with third parties, when drafting a subsequent AMI, parties must consider which AMI provision should prevail. If the subsequent AMI is to prevail, then the consent of the parties to the preexisting AMI must be obtained. Furthermore, if a party to an AMI already owns existing leases within the AMI boundaries, parties should consider whether such an owner should offer to the other parties a proportionate share of those leases or to specifically exclude such leases from the AMI provision.

In addition, occasionally parties will agree to certain "pre-approved acquisitions," pursuant to which the non-acquiring parties will be obligated to participate in clearly defined acquisitions.47 These pre-approved acquisitions are exempt from the standard offer and election mechanism.

Parties should also consider whether exclusive acquisition rights within the AMI are warranted. Exclusive leasing rights may be warranted where: (i) one party has greater expertise or knowledge of the status of leases within the area; (ii) one party is only a financial partner; (iii) one party is already far along in the leasing process; (iv) doing so avoids driving up acquisition costs by competing against one another; and (v) one party is more selective than the other. Occasionally, it may be beneficial for a particular party to have exclusive leasing rights on one portion of the AMI while another party has exclusive leasing rights in a different portion of the AMI.

D. Successors and Assigns Issues

In order to provide constructive notice to third parties of the existence of the AMI, either (i) the agreement containing the AMI provision or (ii) a memorandum thereof containing a description of the lands and the essential elements of the AMI provision, should be filed in the public records of the county where the AMI is located. In effect, the parties to an AMI should provide constructive notice to third parties contemporaneously with the execution of the agreement containing the AMI in order to ensure that the AMI provisions are enforceable against third parties. For instance, if a party that is subject to the AMI acquires an acquired interest but does not offer the applicable participation share to the other AMI parties, and thereafter conveys such acquired interest to a third party, the other AMI parties will have superior rights to their

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Farmee on or before the expiration of the fifteen (15) business day period, it shall be deemed that such Farmor elected not to participate in the Unearned AMI Interests. Farmee shall immediately thereafter execute and deliver to each participating Farmor its designated interests in such Unearned AMI Interests in the form of the attached Exhibit B (including special warranty language), and such assigned interests shall bear only their proportionate shares of those burdens that existed at the time of acquisition by Farmee."

[47] *E.g.*, "If the acquiring party identifies and acquires or contracts to acquire an acquired interest, the acquiring party shall provide to the other party an acquisition notice with respect to such acquired interest and the other party shall be obligated to participate with the acquiring party in the acquisition of such acquired interest if and to the extent that the purchase price paid or to be paid by the acquiring party does not exceed $1,250 per net mineral acre and the total amount of any one acquisition notice is not greater than $2,500,000."

participation share *vis-à-vis* such third party so long as such third party had notice (either actual or constructive) of the AMI prior to its acquisition.

A different question may arise as to whether the third party in the example discussed above, after its acquisition of an acquired interest from an AMI party, would itself be subject to the AMI. If so, any acquired interest within the AMI that such third party acquires after said acquisition would be subject to the offer mechanism set forth in the AMI. The answer will depend on whether such third party either expressly assumed the original AMI party's rights and obligations under the AMI agreement or, alternatively, whether such third party is deemed to have assumed the AMI provisions because such provisions are deemed to be covenants running with the land. The resolution of this issue can vary based on the facts of the situation and even the state in which the assets are located. In Texas, AMI provisions of which proper and timely notice have been given are viewed as covenants running with the land.[48] By contrast, in North Dakota[49] and Wyoming,[50] AMI provisions have been found not to be covenants running with the land.

VI. <u>Assignability and Exit Strategies</u>

In Nontraditional Joint Ventures, Investors and Operators often set forth various types of transfer restrictions in favor of each party (particularly during the period prior to the full utilization of the Carry Consideration). From the Investor's perspective, it has entered into the joint venture specifically due to the Operator's expertise within the exploration area. From the Operator's perspective, it may have concerns regarding the ability of an Investor's assignee to satisfy the Carry Consideration obligations. Parties will often include specific exceptions to transfer restrictions in the case where a particular section, or unit, has been fully developed. Additionally, Investors will often negotiate for an exception to apply if the Investor pre-pays the remaining Carry Consideration in a lump sum. However, such pre-payment rights are usually not available until at least a minimum amount of time (for example, two to three years) has passed. Once the Carry Consideration has been fully satisfied, assignability is generally governed by the provisions set forth in the applicable JOA.

A. <u>Preferential Purchase Rights</u>

Preferential purchase rights provide the holder thereof with an opportunity to purchase the interests of another party upon such party's election to sell its interest in the jointly-owned properties. The specific terms and conditions upon which a preferential purchase right holder must accept in order to exercise its right should be clearly set forth in the applicable transaction document.

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[48] See *Westland*, 637 S.W.2d at 908–11.

[49] *See Golden v. SM Energy Company,* 826 N.W.2d 610 (N.D. 2013) (holding that an AMI agreement was not a covenant running with the land and therefore the successor had not assumed the AMI as a matter of law and remanding the case for a determination as to whether the parties to the assignment had intended that the successor was to assume the AMI agreement).

[50] *Mountain West Mines, Inc. v. Cleveland-Cliffs Iron Co.*, 376 F. Supp. 2d 1298 (D. Wy. 2005), *aff'd in part, rev'd in part on other grounds*, 410 F.3d 947 (10th Cir. 2006).

The A.A.P.L. Form 610 – Model Form Operating Agreement – 1989 contains a standard preferential purchase right provision that includes the following language:

> Should any party desire to sell all or any part of its interests … in the Contract Area, it shall promptly give written notice to the other parties, with full information concerning its proposed disposition, which shall include the name and address of the prospective transferee …, the purchase price, a legal description … and all other terms of the offer. The other parties shall then have an optional prior right, for a period of ten (10) days after the notice is delivered, to purchase for the stated consideration, on the same terms and conditions, the interest which the other party proposes to sell…. There shall be no preferential right to purchase in those cases where any party wishes to mortgage its interests, or to transfer title to its mortgagee in lieu of or pursuant to foreclosure…, or to dispose of its interests by merger, reorganization, consolidation, or by sale of substantially all of its Oil and Gas assets to any party, or by transfer of its interests to a subsidiary or parent company or to a subsidiary of a parent company, or to any party in which such party owns a majority of the stock.[51]

As set forth in the last sentence above, several transactions, such as sales to subsidiaries, mergers, reorganizations, and sales of stock, will generally not trigger the preferential purchase right. This issue was the focus in *Tenneco, Inc. v. Enter. Prods. Co.*, wherein the Texas Supreme Court held that (1) a stock sale did not trigger a preferential purchase right absent express language to that effect and (2) multiple separate transactions will not be viewed as a single transaction to determine whether a preferential purchase right has been triggered.[52] In this case, Tenneco Oil Co. ("Tenneco Oil") and several other companies, including Enterprise Products Company (collectively, "Enterprise"), co-owned a natural gas fractionation plant subject to a JOA, under which each party's interest was burdened by a right of first refusal.[53] The right of first refusal was limited to asset sales and did not apply to transfers to wholly-owned subsidiaries.[54] In a series of related transactions, Tenneco Oil conveyed its interest in the fractionation plant to its wholly-owned subsidiary, Tenneco Natural Gas Liquids ("Tenneco Gas"), and then conveyed all of the stock of Tenneco Gas to Enron Gas Processing Company ("Enron"), which changed the name of the company to Enron Natural Gas Liquids.[55] Tenneco Oil had initially offered the assets for sale before settling on the stock sale structure, and for tax purposes, Tenneco Oil and Enron treated the transaction as an asset sale.[56] Enterprise's lawyers argued that no matter how the parties structured the transaction, it was, in substance, a transfer of an ownership interest, which invoked the right of first refusal.[57] However, the Texas Supreme Court disagreed with such argument, and ruled in favor of Tenneco Oil, explaining as follows:

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[51] See A.A.P.L. Form 610 – Model Form Operating Agreement 1989, Article VIII.F.

[52] 925 S.W.2d 640, 646 (Tex. 1996).

[53] *Id*. at 641-642.

[54] *Id*. at 644.

[55] *Id.* at 642.

[56] *Id.*

[57] *Id*. at 645-646.

> Sound corporate jurisprudence requires that courts narrowly construe rights of first refusal and other provisions that effectively restrict the free transfer of stock…. Viewing several separate transactions as a single transaction to invoke the right of first refusal compromises the law's unfavorable estimation of such restrictive provisions.... Moreover, the plain language of the Restated Operating Agreement provides that only a transfer of an ownership interest triggers the preferential right to purchase; it says nothing about a change in stockholders. The Enterprise Parties could have included a change-of-control provision in the agreements that would trigger the preferential right to purchase. None of the agreements among the parties contained such a provision. We have long held that courts will not rewrite agreements to insert provisions parties could have included or to imply restraints for which they have not bargained.[58]

This process has become commonly referred to as the "Texas Two-Step."[59] Parties may wish to avoid this result through negotiation and careful drafting.[60]

B. Maintenance of Uniform Interest Provisions

If the prospect lands are located within the contract area of a JOA, then a transfer of portions of the acreage and specific depths will quite often violate the maintenance of uniform interest ("MUI") clause in the JOA. The standard MUI provision states:

> For the purpose of maintaining uniformity of ownership in the Contract Area … no party shall sell, encumber, transfer or make other disposition of its interest in the Oil and Gas Leases and Oil and Gas Interests embraced within the Contract Area or in wells, equipment and production unless such disposition covers either:
>
> 1. the entire interest of the party in all Oil and Gas Leases, Oil and Gas Interests, wells, equipment and production; or
>
> 2. an equal undivided percent of the party's present interest in all Oil and Gas Leases, Oil and Gas Interests, wells, equipment and production in the Contract Area.[61]

The MUI provision has been described as "the most ignored provision" in the standard JOA.[62] The provision is widely disregarded and often breached. Even if a breach is discovered, it is usually tolerated, because the general view is that the remedy for breach is actual damages,

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[58] *Id*.

[59] *See* Robert J. Sergestetter, *Preferential Rights to Purchase: The Basics, and the Most Interesting Pref. Rights Case You've Never Heard About*, 5 HLRe 43, 49 (2015), and additional sources cited in FN9 thereof.

[60] For an interesting draft of a preferential right to purchase provision designed to address not only the "Texas Two-Step" issue but also other issues with the standard clause, *see* Pierce, "*In the Classroom: Drafting a Better Preferential Right to Purchase Clause*," CAIL Institute for Energy Law Energy Law Advisor, Vol. 8, No.4 (September 2014).

[61] A.A.P.L. Form 610 – Model Form Operating Agreement 1989, Article VIII.D.

[62] Terry I. Cross, *supra* note 12 at 213 (1999).

and no damages can typically be shown by the non-breaching party. However, despite the fact that the MUI provision is often disregarded, it is rarely actually stricken from the model form JOA.[63] In the authors' view, however, parties should give serious consideration to striking it.

Most multi-well farmouts and Nontraditional Joint Venture arrangements clearly breach the standard MUI provision. In a multi-well farmout, for example, not only does the Farmee earn an interest only as to the prospect interval (rather than a uniform interest across all depths), but the Farmee earns additional acreage as each earning well is drilled (as opposed to a uniform interest across all of the lands within the prospect area).

The MUI provision seems to rarely be litigated. In one case, however, the Texas Court of Appeals in Houston awarded damages for the breach of an MUI provision. In *ExxonMobil Corp. v. Valence Operating Co.*, ExxonMobil breached an MUI provision under a JOA by farming out its interest in the Cotton Valley Sand formation but retaining its interest as to other depths.[64] The facts showed that the breach of the MUI provision by ExxonMobil forced Valence to elect whether to participate in new wells that could have more efficiently been recovered via a dual completion from existing wellbores.[65] The court determined the cost that would have been incurred had the reserves been accessed from existing wellbores, and deducted that figure from the cost of the new wells.[66] Valence was awarded damages equal to its pro rata share of the difference.[67] Valence was also awarded damages to recover non-consent penalties that it had incurred because it had not responded to a drilling proposal from ExxonMobil's Farmee.[68] However, these damages did not result from the MUI breach, but from ExxonMobil's failure to give the required notice to Valence that it had farmed out its interest in the Cotton Valley Sand formation.[69]

The *Valence* case involved a unique circumstance in which a party was able to prove actual monetary damages as a result of the breach of an MUI provision. Notwithstanding the lesson of *Valence*, the provision is still often ignored by parties to a JOA. Still, the prudent course of action for a Farmor is to seek a waiver of the MUI from the other working interest owners under the JOA. A multi-well farmout will typically result in not just one, but a series of breaches of the MUI provision as the Farmor assigns portions of its acreage to the Farmee as each successful earning well is drilled. Accordingly, the parties to a farmout agreement should attempt to seek a blanket waiver of the MUI provision that allows for multiple transfers to the Farmee, and thereby avoid the need to send a separate waiver request for each assignment to the Farmee.[70]

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[63] Compare to the preferential right to purchase clause in Article VIII.F of A.A.P.L. Form 610 – Model Form Operating Agreement 1989, which is often expressly crossed out or otherwise declared inapplicable.

[64] 174 S.W.3d 303 (Tex. App. - Houston 2005).

[65] *Id*.

[66] *Id* at 315-316.

[67] *Id*.

[68] *Id* at 317-318.

[69] *Id*.

[70] The same strategy should be employed in connection with consents-to-assign in oil and gas leases. For example,

C. Rights of First Opportunity

Rights of first opportunity give parties the right to preempt a sale to a third party by having the first opportunity to purchase the other party's interest. These provisions are often used as a compromise to including a preferential purchase right or right of first refusal. Rights of first opportunity, however, are significantly less restrictive than preferential purchase rights and rights of first refusal, which, depending on the context, may be advantageous or disadvantageous.

Two common rights of first opportunity are rights of first negotiation and rights of first offer. Rights of first negotiation typically require a party wishing to sell all or part of its interest in the applicable contract area to notify the other party of the price and other terms under which it is willing to sell its interest. The non-selling party then has a limited time to elect to enter into negotiations to purchase the selling party's interest. If the non-selling party elects to pursue such negotiations, the parties shall undertake good faith negotiations to agree to mutually acceptable terms and conditions for the sale of the selling party's interest to the non-selling party, and upon such agreement, shall exercise good faith in consummating such sale in a timely manner. If the parties fail to reach agreement within some specified period of time (or if the non-selling party elects not to enter negotiations), the selling party will be free to sell its interest to any third party, provided that the total consideration received cannot be less than the offered price, terms, and conditions described by the selling party in its notice to the non-selling party.

Rights of first offer are similar to rights of first negotiation, but do not include the negotiation covenant. Thus, while the non-selling party has a right to make an initial offer for the selling party's applicable interest, the selling party has the discretion to accept such offer or negotiate with other potential buyers.

D. Drag-along Provisions

Drag-along provisions provide a party with the right to force the other party to join a sale of interests in jointly-owned properties. For example, the parties may include a provision similar to the following:

> If a Party (the "Selling Party") receives an acceptable offer from a bona fide unaffiliated third party, through solicitation or otherwise, to sell all of its interest in the Contract Area, then the Selling Party may require the other Party, upon 30 days prior written notice, to accept and sell all of its interest in the Contract Area under identical terms (including price (proportionately decreased or increased, if applicable), effective date, and closing date) accepted by the Selling Party. The Parties shall cooperate fully in consummating any sale made pursuant to this provision, including the execution of a joint purchase and sale agreement.

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if an Investor will only be earning individual wellbore assignments initially, with the potential for a complete lease assignment at a subsequent date, a broad consent authorizing the lease assignment to be made in whole or in multiple parts will avoid the necessity of seeking a new consent for each subsequent partial lease assignment.

The theory behind drag-along provisions is that some buyers will not want a partner and will only want to buy all of the interests. Having a drag-along provision enables the selling party to address that issue by giving it the contractual right to commit the entire interest to a sale.

To protect the party who may not want to sell, some drag-along provisions will allow the party being dragged along to have the preemptive right to match the terms of the third party offer and buy out the party seeking to sell.

E. <u>Tag-along Provisions</u>

Tag-along provisions provide a party with the right to join the other party's sale of interests in jointly-owned properties. For example, the parties may include a provision similar to the following:

> If either Party proposes to sell or otherwise transfer or convey any of its interest in the Contract Area, it shall promptly notify the other Party in writing regarding such proposed conveyance. The non-selling Party shall then have fifteen (15) Business Days from the date of receipt of such notice to notify the selling Party whether it desires to participate in such proposed conveyance. If the non-selling Party does not so notify the selling Party within such fifteen (15) Business Day period, the non-selling Party shall be deemed to have waived such right. If the non-selling Party elects to join the proposed conveyance, the selling Party shall notify the prospective purchaser … and shall use commercially reasonable efforts to cause the prospective purchaser to include the non-selling Party's interests in the transaction.

These provisions provide an out to the non-selling party if it does not want the third party buyer as its new partner in the jointly-owned properties.

Note that tag-along provisions often include various modifications. For example, in some joint venture arrangements, the selling party must notify the prospective purchaser of the other party's desire to join the proposed sale, and the proposed sale must be conditioned on the prospective purchaser acquiring the interests of both parties. Additionally, some joint venture arrangements will provide that if the prospective buyer is not willing to acquire a total percentage interest greater than that owned by the selling party, the interest acquired by the buyer must be acquired from both parties in accordance with their proportionate undivided interests. Consider the following example:

> Party A owns an undivided 80% interest and Party B owns an undivided 20% interest. The Buyer wants to acquire Party A's undivided 80% interest. Party B opts to tag along, but the Buyer does not want to acquire more than an undivided 80%. In this scenario, the Buyer must acquire an undivided 64% (80% of 80%) from Party A, and an undivided 16% (20% of 80%) from Party B.

Often, the inclusion of tag-along provisions follows the inclusion of tag-along provisions. That is, if one party seeks the right to require the other party to join a sale, the other party will typically seek the right to join in the other party's sale.

F. Buy-sell Provisions

Buy-sell provisions (often referred to as "Deadlock Provisions") may be proposed by a particular party to address those situations where one party wants to take out the other. These provisions will typically take the form of one of the following three nicknamed provisions: "Russian Roulette," "Texas Shootout," and "Dutch Auction."

The "Russian Roulette" buy-sell provision allows one party (Party A) to make a cash offer to buy out the other party's (Party B's) share of the joint interests. Upon receiving the offer, Party B has only two options: either (a) sell its interest to Party A at the specified price, or (b) buy out Party A's share under the same terms offered by Party A. Party A is then obligated to either buy or sell, depending on the election of Party A.

Under a "Texas Shootout" buy-sell provision, Party A may offer to buy all of the interest held by Party B for a specific price. Party B may either accept this offer, or make an alternative offer to buy Party A's interest for a *higher* price. The same right is then extended to Party A. This process of offer and counteroffer can continue through many "rounds," with each bid required to exceed the previous highest bid by a specified percentage, until either party declines to outbid the other, at which point that party becomes obligated to sell to the higher-bidding party at the last price offered. A variation to this provision (sometimes called a "Mexican Shootout") sets forth that each party must make a sealed written cash bid for the purchase of the other party's interest. The bids are submitted concurrently to a neutral third party. The party with the lower bid is forced to sell to the other party.

Finally, the "Dutch Auction" buy-sell provision (which is similar to the "Texas Shootout") provides for each party to make sealed bids stating the *minimum* cash price for which it would be willing to sell its share of the joint interests. The party with the lower bid is forced to sell to the other party.

VII. Current and Emerging Legal Issues

A. Commodity Price Uncertainty

The current volatility in oil, in particular, and gas prices has prompted joint venture parties to look for ways to address commodity price risk within the joint venture deal structure. Operators and Investors may consider numerous types of proposals in attempting to find a methodology acceptable to both parties.

One method for parties to partially address price risk is to adjust the interest to be held by the Investor upon the occurrence of a specified triggering event. For example, consider the basic deal structure discussed in Section III.A of this article in which (a) the Investor is to pay 100% of the capital costs until a Drilling Commitment has been fully funded; (b) the Investor will receive an 85% interest until it has received a specified IRR; and (b) at that point, the Investor's interest will be reduced to 15%. To address price risk, the parties agree to an adjustment of the Investor's reversionary interest in the event of certain fluctuations in the commodity price – for example, they may agree to look at the most relevant price index (such as WTI or Brent) on a certain future date, and if the price is below some negotiated price threshold on that date, the Investor's interest will only be reduced to, say, 25%, rather than 15%. Conversely, they may agree that if the price index has increased above some certain threshold, the Investor's interest will be reduced even further – to say, 10%, rather than 15%.

If the Investor has hedging contracts in place, another method to address the Investor's price risk is to factor the effect of the Investor's hedging contracts into the return calculations. The following language illustrates this basic concept. In this example, the non-italicized language comprises a typical definition of "payout," and the italicized language implements the adjustment for the Investor's hedging results:

> For purposes of this Agreement, "Payout" shall mean the first day of the month following the date upon which the proceeds of all hydrocarbons produced and sold from a Well (together with any proceeds recoverable from insurance *and any Hedge Revenues*), after deducting (x) royalties, overriding royalties, and all other burdens affecting the Leases**,** (y) taxes (including production, severance, excise and ad valorem taxes chargeable to the working interest), *and (z) any Hedge Expenses*, equal one hundred percent (100%) of the costs incurred in locating drilling, testing, logging, fraccing, perforating, equipping, and Completing and the costs of preparing and operating such Well, including reasonable legal and title expenses, and the costs of workovers and repairs conducted prior to Payout, *where (a) "Hedge Revenues" shall mean amounts actually received under Swap Agreements, (b) "Hedge Expenses" shall mean amounts actually paid under Swap Agreements, and (c) "Swap Agreements" shall mean any price swap agreement entered into by [X] to hedge anticipated production from the Leases, as notified to [Y] by [X], together with a copy of each such swap agreement.*

Note that both these provisions will have a corresponding effect on the promoted party; therefore, they are more likely to be accepted by an Operator who has a similar outlook on future commodity prices as that of the Investor, or a similar degree of tolerance (or aversion) to commodity price risk. In the first example, the Operator's exposure to a decrease in commodity price risk is mitigated by having a greater reversionary working interest, but the upside to the Operator of a commodity price increase is mitigated by it having a lower reversionary working interest. In the second example, the Operator's interest increase will be delayed (if prices go up and, as a result, Hedge Expenses are incurred) or will occur sooner (if prices go down and, as a result, Hedge Revenues are received).

Obviously, when factoring hedging positions into the terms of the agreement, the parties may negotiate countless variations of the basic concept described above. The following are just a few of the possible variations:

1. Limits on the total amount and/or the percentage of production to which the adjustment will apply;

2. Limits on the duration of the adjustment;

3. Minimum hedge prices for swaps;

4. Variations that apply other derivatives options such as put spreads or collars;

5. Variations that also take into account the Operator's hedging position;

6. Variations that require the Operator's reasonable prior approval of the Investor's hedging contract; and

7. Variations that limit the credit risk associated with the hedging contracts to only the party who has the applicable hedging contract in place (or alternatively, provisions that limit the applicability of the adjustment mechanism to only hedging contracts with counterparties with specified minimum credit ratings).

Another protection against price risk is to incorporate certain performance conditions tied to the applicable commodity price. For example, an Investor who is otherwise obligated to carry an Operator's drilling costs may negotiate to condition that obligation on the applicable index price not dropping below a certain designated floor price.

B. Royalty Obligations

Consider the following fact scenario:

> The Investor is a large foreign gas provider and power producer in a large Asian Pacific country. It is currently constructing a large LNG import terminal, which is necessary because the Investor provides gas to more than a million households. It has substantial equity in an approved U.S. LNG export facility, along with a long-term liquefaction tolling agreement providing for the export of LNG from the U.S. to Asia. Ownership of U.S. natural gas interests would ensure the Investor of a successful U.S. natural gas export strategy. The Operator is over-weighted on the gas side of its portfolio, and is seeking to monetize some of its gas assets and use the proceeds to acquire liquids. The Investor and the Operator discuss a joint venture whereby the Investor will acquire a specified non-operating working interest share of the Operator's shale gas assets. The Investor anticipates selling gas directly to the U.S. LNG export facility entity in which it owns an equity interest for prevailing market prices (estimated between $3 and $5/Mcf). Back at home, the Investor expects to receive approximately $20/Mcf for the sale of such gas.

The foregoing scenario illustrates an emerging legal issue with respect to the calculation of royalty. If the Investor calculates royalties based on prevailing market prices in the U.S. (or prices received for a portion of the produced gas under a gas sales contract) rather than the price received by the Investor in the foreign country, this may expose the Investor to claims from lessors that royalties were improperly calculated.

The U.S. Court of Appeals for the Ninth Circuit addressed this issue in *Marathon Oil Company v. United States Cook Inlet Region, Inc.*[71] Marathon Oil Company ("Marathon"), which owned federal oil and gas leases in Alaska, had sold 84% of its natural gas under a long term sales contract with Alaska Pipeline Company, and transported the other 16% of its natural

[71] 807 F.2d 759 (9th Cir. 1986).

gas to an LNG plant that it co-owned with a third party.[72] Marathon transported such LNG in tankers to Japan where it was ultimately sold for a significantly higher price than received by Marathon under the long term sales contract.[73] Notwithstanding the foregoing, Marathon calculated and paid all of its royalty obligations based on the price received under its long term sales contract (rather than a portion thereof (specifically, 16%) based on the price received from sales in Japan.[74] The underlying oil and gas leases set forth that royalties were to be computed in accordance with the "Oil and Gas Operating Regulations," which provided that "Under no circumstances will royalty be computed on less than the gross proceeds accruing to the lessee or operator from the sale of leasehold production."[75] Ultimately, the Ninth Circuit upheld a ruling by the MMS that required Marathon to calculate royalties burdening the gas sold in Japan using the price received in Japan, less certain actual costs.[76]

While this issue may significantly impact foreign (and other) Investors that sell produced natural gas to other markets, it may also impact Operators transacting with such Investors, as such Operators, being co-working interest owners, may have joint and several liability for payment of lease royalties under the applicable state law.[77]

One potential solution to this issue is to not sell gas directly to the U.S. LNG export facility entity in which the applicable investor owns an equity interest. However, this may lead to claims from lessors that the failure to sell to such entity is a breach of the implied duty to market at the best price. Texas courts utilize the following two-pronged test in analyzing the implied duty to market: the lessee must (i) market the production with due diligence and (ii) obtain the best price reasonably possible.[78] While no case authority directly on point was found, several key principles under Texas law support a finding that the sale of gas produced from the lease at prevailing market prices will fulfill a lessee's obligation to market the gas, notwithstanding the possibility of higher priced gas sales elsewhere.[79]

Another possible solution is for the Investor to sell down its equity in the LNG export facility entity to less than a controlling interest. However, the viability of this potential solution

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[72] *Id.* at 761-763.

[73] *Id.*

[74] *Id.*

[75] *Id.* at 765-766.

[76] *Id.*

[77] *See, e,g., Sharp v. Beacon Oil & Ref. Co.*, 108 S.W.2d 870 (Tex.Civ.App. – Texarkana 1937, writ dism'd).

[78] *Cabot Corp. v. Brown*, 754 S.W.2d 104, 106 (Tex. 1988).

[79] See *Hurd Enterprises, Ltd. v. Bruni*, (Tex.App. – San Antonio 1992, writ denied) (holding that an operator does not owe royalty owners a fiduciary duty and is not required to place the interests of the royalty owner before its own). See also *Clifton v. Koontz*, (Tex. 1959) (holding that the reasonably prudent operator standard explicitly protects the lessee's profit motive in other contexts). See also *Union Pac. Res. Group, Inc. v. Hankins*, (Tex. 2003) (holding that the simple fact that higher priced sales take place in the market does not by itself constitute a breach of the duty). See also *Occidental Permian Ltd. v. Helen Jones Found.*, (Tex. App. – Amarillo 2011, pet. denied) (holding that (i) courts have tended to protect sales of minerals that occur at a generally prevailing market price and (ii) a royalty owner must provide specific expert testimony to show that the duty to market has been violated even where an operator's affiliates are involved in the purchase of gas from the operator).

is tied to how the underlying oil and gas lease defines "affiliate," as that will determine whether the sale to such entity is an unaffiliated transaction. From the Operator's perspective, a contractual solution to this issue is to seek a strong indemnity from the Investor, and further, to ensure that such indemnification obligations are covered by the applicable security instruments to be provided by the Investor (such as a parent guaranty).

C. Tax Implications of Overriding Royalty Reservations

As noted above, one component of the consideration in many joint venture transactions is the reservation of an overriding royalty interest by the original owner of the oil and gas leases. Although the practice of retaining overrides when divesting leases has been prevalent in the industry for ages, lawyers and land and business development professionals should beware of certain potential adverse tax consequences that can result from this practice. Specifically, when an overriding royalty interest is retained in connection with the sale of an oil and gas lease, the transaction is treated as a lease, rather than a sale, for federal income tax purposes.[80] Consequences of this tax treatment include the following:

1. The sales proceeds are treated as an advance royalty, taxable as ordinary income, rather than capital gains (resulting in a higher tax rate except for certain corporations).[81]

2. The sales proceeds are offset by cost depletion, rather than the seller's entire basis in the transferred lease.[82]

3. The assignor cannot use the sales proceeds in a tax-advantaged "like-kind exchange," and likewise, the assignee would not be able to use the acquired assets as part of a reverse like-kind exchange.[83]

Under certain circumstances, however, and with the guidance of expert tax counsel, there may be creative ways to structure the transaction so as to avoid it being treated as a lease under federal income tax rules.

D. Antitrust Issues

Consider the following fact scenario:

> Party A and Party B are each independent exploration and production companies who are acquiring oil and gas leases in the same geographic area. The parties commence discussions regarding a potential formal collaboration agreement to acquire oil and gas leases and develop new gathering lines. However, these discussions are abandoned. Nevertheless, Party A and Party B agree on a Memorandum of Understanding ("MOU") to jointly bid on four leases at upcoming BLM auctions. Under the MOU, only Party A will bid at the auctions,

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[80] *See Palmer v. Bender,* 287 U.S. 551 (1933).

[81] *See Hogan v. Commissioner*, 141 F.2d 92 (5th Cir. 1944); *Cullen v. Commissioner*, 118 F.2d 651 (5th Cir. 1941).

[82] Treas. Reg. § 1.612-3(a)(1).

[83] *See Richard Wayne Crooks v. Commissioner,* 92 T.C. 816 (1989).

> the parties set a maximum price that Party A can bid, and if Party A acquires the leases, Party B will receive a fifty percent (50%) interest at cost. Thereafter, Party A and Party B complete their negotiations and enter into a formal agreement to jointly acquire and develop oil and gas leases and gathering lines within a particular contract area.

The foregoing fact scenario illustrates the basic facts in *U.S. v. SG Interests I, Ltd.*, wherein the Justice Department Antitrust Division filed a civil suit against the defendants under U.S. antitrust laws (claiming that the defendants engaged in unlawful bid-rigging) and the False Claims Act (claiming that the defendants falsely certified that bids were "arrived at independently" and were "tendered without collusion with any other bidder for the purpose of restricting competition").[84] Under this civil suit, both defendants signed consent decrees requiring each company to pay $275,000 in penalties.[85] Note that in this case, the Justice Department brought a civil case, and not a criminal case, despite the fact that the Justice Department often pursues criminal charges in cases involving bid-rigging at auctions. Perhaps this decision took into account that the defendants had discussed a broad collaboration arrangement and, importantly, eventually entered into such an agreement.

A recent case involving criminal (rather than civil) charges was *State of Michigan v. Encana Corp.*, wherein the Michigan Attorney General filed criminal bid-rigging charges against Encana Oil and Gas USA ("Encana") and Chesapeake Energy Corporation ("Chesapeake"), alleging that the companies conspired in 2010 to refrain from bidding against each other at public oil and gas lease auctions and in private negotiations for oil and gas leases.[86] On May 5, 2014, Encana settled the case, agreeing to pay the State of Michigan a fine of $5 Million and to plead no contest to one criminal antitrust violation.[87] Chesapeake, on the other hand, has not settled and is continuing to fight the criminal antitrust charges (which were expanded on June 5, 2014, to include additional criminal racketeering and fraud charges).

In addition to the State of Michigan criminal case, Northstar Energy has a pending civil action (filed in February, 2013) against Encana and Chesapeake in the Western District of Michigan, alleging violations of both the Sherman Act and state antitrust laws, collusion, civil conspiracy, and various other tort claims. The suit claims that Northstar owned 9,838 acres in the Utica and Collingwood Shale in Northern Michigan, and that after it had received lease offers from both defendants, Encana withdrew its offer, and Chesapeake then drastically reduced its offer. In 2014, the Court denied the defendants' Motion to Dismiss on all the antitrust counts.[88]

There are several ways for parties to mitigate potential antitrust risks, including the following:

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[84] No. 12-cv-00395-RPM, 2012 WL 6196131 (D. Colo. Dec. 12, 2012).

[85] *Id.*

[86] Case no. 15-554CP, Circuit Court for the County of Ingham (2014).

[87] *Id.*

[88] *Northstar Energy, LLC v. Encana Corporation, et al.*, Case No. 1:2013-cv-00200, Michigan Western District Court.

8. Avoid collaborations that involve only joint leasing. Collaboration agreements solely related to leasing – especially leases that the parties might independently have bid for – present significant antitrust risks and may easily be characterized by the government as *per se* illegal price fixing. In contrast, collaboration agreements whose purpose is to pool resources of two companies to accomplish tasks they could not perform on their own (such as oil and gas exploration and product and infrastructure development) are more likely to pass antitrust muster – *assuming* that the joint leasing component of the collaboration is "reasonably necessary" to achievement of the collaboration's overall cost-reduction and efficiency-enhancing effects.

9. Enter into a formal collaboration agreement. Ad hoc, informal collaboration is much more likely to attract antitrust interest than a more formal, carefully documented collaboration, which recites the procompetitive purposes of the collaboration and confines the joint activities to those reasonably necessary to fulfilling the procompetitive purposes.

10. The collaboration should include joint activity resulting in a collaboration that will have procompetitive and efficiency-enhancing purposes and effects, such as resulting in output expansion (such as increased production), facilitating entry and expansion by smaller E&P companies who may not have been able to do so on their own, and reducing costs for both companies.

11. Identify why it is necessary to bid jointly (if that is part of the collaboration). The antitrust agencies will weigh any potential anticompetitive harms (such as decrease in competition through joint bidding) against any procompetitive benefits, and may look at whether joint bidding was "reasonably necessary" to the collaboration and whether there were less restrictive means "reasonably available" to achieve the goals of the collaboration.

12. Share risk. Doing so shows that the parties are willing to pool risks as well as resources and demonstrates that the collaboration is not simply a cover for collusive activities. This is often an important factor in the Justice Departments' analysis.

13. Limit information sharing regarding matters outside the particular collaboration at issue. Entering into collaboration or participation agreements with a competitor may create opportunities to share competitively sensitive information. Implement safeguards to limit information exchange, such as only exchanging information reasonably necessary to the collaboration and not exchanging information on leasing plans or other competitively sensitive matters outside the scope of the collaboration.

14. Rigorously adhere to government certification and procurement regulations related to bidding on leases.

15. Be proactive – rather than reactive – in consulting with antitrust counsel.

Antitrust analysis is particularly important before entering into a collaboration between parties who may collectively have a dominant position in any local geographic areas. Both the Colorado and Michigan antitrust cases appear to have involved situations where the collaborating parties were, in fact, dominant in local areas.

VIII. Conclusion

As new geological formations are discovered, unconventional exploration continues to expand, new technology emerges, new capital sources become available, and commodity prices show perhaps as much volatility as ever, the structures of oil and gas joint ventures seem to be rapidly evolving – seemingly limited only by the creativity of the multitude of oil company executives, business development professionals, Wall Street and foreign investors, investment bankers, tax advisors, landmen, engineers, geologists, and lawyers who all play a role in these transactions. This paper has only scratched the surface of the many legal issues and relevant law that come into play in negotiating and documenting oil and gas joint ventures. Companies who enter into these transactions should engage legal counsel who not only have experience handling sophisticated transactions, but who also have a superior knowledge of the large body of law that is applicable to these transactions, including tax law, antitrust, capital markets, finance, bankruptcy, and, most importantly, oil and gas law.