ESTATE PLANNING WITH MINERAL INTERESTS

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ESTATE PLANNING WITH MINERAL INTERESTS

I. INTRODUCTION

Using a statistical measure of the amount of energy to produce a dollar of world GDP, over the last 50 years, the world has become twice as efficient; however, the global consumption of primary energy consumption is three times higher today than it was in 1965. Translated, that means we are an energy hungry planet, and that trend is not likely to shift significantly in the near future.[1]

Given the trend towards more energy consumption, the oil and gas industry has developed significant technological advances in the production of oil and gas resources, primarily horizontal drilling and hydraulic fracturing ("fracking"). Those technological advances have resulted in transformation of the U.S. oil and gas industry. Regions of the United States which previously were not considered producers of oil and gas are now actively producing minerals (*e.g.*, the Eagle Ford shale play in South Texas, the Bakken shale in North Dakota, the Utica shale in West Virginia and Ohio, and the Marcellus shale in Pennsylvania). As a result, the ownership of minerals has produced significant wealth for individuals who previously may not have considered their mineral ownership a significant asset of their estate. Therefore, it is important that tax and estate planning advisors understand the fundamentals of mineral ownership and the legal and tax considerations associated with ownership of minerals, as well as how those considerations interplay with the estate planning strategies widely utilized for other assets.

This paper provides a brief discussion of the various economic interests in mineral ownership, and certain issues related to the Federal income and estate and gift tax consequences associated with the ownership of mineral interests. It also addresses some of the State of Texas taxation issues associated with mineral interests, as well as some of the fiduciary law considerations. This paper is not intended to be a thorough discussion of the property, environmental and regulatory law aspects of mineral ownership and development, nor is it intended to be a thorough discussion of the Federal tax law consequences for the various owners of the mineral interests.

II. AN OVERVIEW OF VARIOUS MINERAL INTERESTS

Under the laws of the State of Texas, ownership of the minerals is considered a component of the ownership of the fee interest, unless some specific act has been taken to separate the minerals, in whole or in part, from the surface. Thus, in the absence of a specific act, the fee simple owner of a parcel of land would own not only the surface, but also one hundred percent of the minerals. It is only through specific legal acts that the ownership of the minerals is severed

[1] See *Eye on the Market: The Arc of History* written by Michael Cembalest, Chairman of Market and Investment

from the fee or carved up into different economic interests (*e.g.*, selling the surface, but retaining the minerals, or leasing all or, more typically, some portion of the minerals).[2]

The typical oil and gas lease divides the ownership of the minerals into working interests and operating interests and passive, non-operating interests (*i.e.*, royalty and overriding royalty interests). The working interest often times is further subdivided into operating working interests and non-operating working interests.

To understand the income tax and estate planning considerations for mineral interests, it is helpful to briefly define the various types of economic interests typically associated with minerals.

A. Working Interest

A working interest is typically created by entering into an oil and gas or mineral lease with respect to all or, more typically, some portion of the owned minerals. The mineral owner (the lessor) will lease to an oil and gas operator (the lessee) specific minerals. The minerals typically are described not only by reference to the surface area, but also by zones of production below the surface. The lease will convey to the operator the right to explore, drill, develop and produce, and sell the oil and gas produced from the subject minerals. Those rights are typically referred to as the "working interest." The owner of the working interest bears all of the cost associated with the exploration and production of the minerals. The working interest owner typically retains all liability associated with the exploration and production of the oil and gas.

A working interest is a fee simple determinable estate in the minerals, which will expire when the lease terminates. The usual lease provides for a primary term, with continues as long as the lease is held by production or, if permitted under the terms of the lease, the payment of delay rentals in the absence of production.

B. Royalty and Overriding Royalty Interests

A royalty interest is created by the lessor retaining an interest in the underlying oil and gas when the working interest is conveyed to the lessee under the oil and gas lease. Simply stated, a royalty interest is a share of the oil and gas produced under the lease, unburdened by any of the costs of production. The royalty is typically stated as a percentage of the gross revenue from production of the oil and gas (*e.g.*, a 1/8th royalty or a 25% royalty).

An overriding royalty interest typically is carved out of the lessee's working interest. In this situation, the original lessee – the working interest owner – enters into a sublease with a third party and retains an "overriding royalty," in much the same manner as the royalty interest was retained under the original lease transaction. For example, assume that the mineral owner (the lessor) enters into an oil and gas lease with Party B (the lessee). Under that lease, the lessor retains a 1/8th royalty interest, and Party B has the working interest, entitled to 7/8th of the proceeds from production of the minerals. Subsequently, Party B enters into a sublease transaction with Party C, retaining a 1/8th overriding royalty, and Party C now owns the working

[2] For purposes of this paper, unless specifically stated otherwise, the discussion will focus exclusively on the ownership of the minerals, regardless of whether the minerals have been previously severed from the surface interest.

interest, entitling it to $6/8^{th}$ of the proceeds from production. It is important o note that the overriding royalty interest exists only so long as the working interest from which it was carved out exists.

C. Lease Bonus Payments, Delay Rentals, and Shut-In Royalty.

A "lease bonus" is paid to the lessor at the inception of the lease as additional consideration for entering into the lease. The lease bonus is intended to compensate the mineral owner for the granting to the lessor/working interest owner of the right to explore for the existence of commercial quantities of producible minerals. It is frequently stated as a "per mineral acre" sum, and it is not dependent upon the subsequent production of oil and gas.

In the typical oil and gas lease, the working interest owner has a stated period of time in which to "hold" the lease through the production of oil and gas from the subject minerals. If, for whatever reason, the working interest owner/the operator wishes to delay the production of the minerals for some period of time beyond the time specified under the lease (e.g., the price of oil and gas has dropped such as to make the production of the mineral economically unfeasible, the working interest owner may hold the lease by payment of a specified "delay rental" until such time as the production of the mineral resumes.

A "shut-in royalty" is a payment by the lessee to the lessor during the period of time a well needs to be shut down. The shut-in royalty, similar to the delay rental, is intended to hold the lease during a period of time in which there is no production of the minerals. One way to think about a shut-in royalty is that it is a substitute for the royalty payment which otherwise would have been paid the lessor if there was commercial production of the minerals.

D. Production Payments

A production payment is similar to a royalty, in that it is typically stated as a specified share of the production, but it is typically limited in duration. Under Treas. Reg. §1.636-3, a production payment must have the following specified elements:

1. A right to a specified share of the production or proceeds from such production;

2. It must be an economic interest as defined under Treas. Reg. §1.611-1(b);

3. It need not be a burden upon an operated mineral interest; it merely needs to be burden upon a mineral interest;

4. It must be satisfiable from the production;

5. It can be measured in monetary terms, as a portion of the volume of production or in terms of time; and

6. It must have an expected life shorter than the duration of the mineral property upon which it is a burden.

E. Net Profits Interest

A "net profits interest" is retained by the mineral owner under the mineral lease, but the royalty to be paid is stated as a percentage of the net profits derived from the production. The net profits interest is distinguished from a royalty payment in that the royalty is stated as a percentage of the gross proceeds from production unburdened by any costs of production.

III. FEDERAL TAX CONSEQUENCES OF MINERAL TRANSACTIONS

While not intended to be a thorough discussion of the Federal income tax consequences of mineral transactions and payments, a brief description is helpful when planning for mineral interests.[3]

A. The Federal Income Tax Consequences of a Lease Bonus Payment

Treas. Reg. § states "[i]n the case of the payor, payment of the bonus constitutes a capital investment made for the acquisition of an economic interest in a mineral deposit… recoverable through the depletion allowance." Interestingly, however, the lease bonus received by the payee is not treated as proceeds from the sale of a capital asset. Instead, the bonus is received by the lessor as ordinary income.[4] The lessor, however, is allowed cost depletion against the lease bonus. Treas. Reg. §1.612-3(a)(1).

B. The Federal Income Tax Consequences of Royalty, Overriding Royalty and Shut-In Royalty Payments

The royalty, overriding royalty, or shut-in royalty received by the royalty owner is received as ordinary income, but the royalty owner is entitled to a depletion deduction against the royalty income. If the royalty owner qualifies as an "independent producer and royalty owner," the royalty owner will be entitled to deduct the greater of cost or percentage depletion. IRC §613A and GCM 22730. The working interest owner is entitled to deduct the royalty payments; therefore they are also excluded when computing the amount of income eligible for percentage depletion.

C. The Federal Income Tax Consequences of Delay Rental Payments

Similarly to the lease bonus payment and the royalty payments, a delay rental is received by the mineral owner as ordinary income; however, unlike those payments, the delay rental is not eligible for any depletion allowance. Treas. Reg. §1.612-3(C)(2).

D. The Federal Income Tax Consequences of Production Payments

If the production payment meets the requirements of Treas. Reg. §1.636-3 discussed above, the production payment is received as ordinary income, subject to depletion. If the payee qualifies as an "independent producer and royalty owner," as discussed above, the payee will be eligible for percentage depletion.

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[3] For a more thorough discussion of the Federal income tax consequences of oil and gas transactions, see BNA Portfolio 605-3rd, *Oil and Gas Transactions*.

[4] See GCM 22730.

IV. TEXAS MARGIN TAX CONSIDERATIONS

The Texas Margin Tax, enacted in 2006 to replace the Texas Franchise Tax and effective as of January 1, 2008, is another potential tax that can apply to mineral interests, depending upon whether the mineral interest is held inside an entity. Unlike the prior Franchise Tax, which applied only corporations and LLCs, the Margin Tax applies to a much broader range of entities, including limited partnerships and, potentially, certain trusts.

A. Passive Entities – An Important Exception

While the new Margin Tax applies to a much broader range of entities, the Margin Tax does provide an exception for "passive" entities. Tex. Tax Code §171.0003 defines a passive entity as a partnership (either general or limited) or a trust the gross income of which consists of at least 90% of "passive income." For this purpose, passive income consists of (i) dividends and interest, (ii) distributions of partnership income, (iii) capital gains on the sale of real estate, commodities or securities; and (iv) royalties, bonuses or delay rentals from mineral properties and income from other non-operating mineral interests. Looking at that test from the opposite perspective, an entity cannot receive more than 10% of its gross income from an active trade or business. Tex. Tax Code §171.0004(e) specifically states, however, that "the ownership of a royalty or a non-operating working interest in mineral rights does not constitute conduct of an active trade or business.

1. Limited Partnerships vs. LLCs

Limited partnerships that meet the passive income exception discussed above are not subject the Margin Tax. Unfortunately, an LLC is not listed as an entity that is eligible to be a passive entity eligible for the passive entity exception.

2. Application of the Margin Tax to Trusts

Trusts are an "other legal entity" under Tex. Tax Code §171.0002(a) and, thus, potentially subject to the Margin Tax. The Texas Tax Code, however, provides that, if the trust is a grantor trust for Federal income tax purposes and all of the grantors are natural persons or charities, the trust is excepted form the Margin Tax. Tex. Tax Code §171.0002(c)(1). This exception applies regardless of whether the trust would otherwise be eligible as a passive entity.

B. Planning Considerations

Given the exceptions for passive entities and grantor trusts, properly structuring the entity into which mineral may be placed can avoid the application of the Texas Margin Tax to that entity.

If the minerals are to be placed into a trust, it is important to cause the trust to be treated as a grantor trust for Federal income tax purposes. Creating grantor trusts is widely utilized by estate planning advisors; therefore, this is fairly natural step to avoid the Texas Margin Tax.

The planning consideration for partnerships, however, is slightly more involved. The creation of family owned entities to hold financial and other investment assets for the family is widely utilized, particularly in the region of the country under the jurisdiction of the U.S. Fifth Circuit Federal Court of Appeals Trusts, but it also is fairly common to use a family owned LLC. If mineral interests are among the investment assets to be placed in the LLC, that entity will be subject to the Texas Margin Tax. As such, the preferred entity, at least as it relates to the Texas Margin Tax, would be a family owned limited partnership. The analysis, however, doesn't stop there, as the partnership must still meet the passive entity test to be excepted from the Margin Tax.

If more than 10% of the entity's income is derived from an active trade or business, then all of that entity's income, including from passive sources, will be subject to the Margin Tax. Therefore, if applicable, it is advisable to separate the working mineral interests from the non-working mineral interests, and to place those different interests in separate limited partnerships. If the ownership is so structured, the entity holding non-working interests should be treated as a passive entity for purposes of the Texas Margin Tax. It is important to note, however, that, if the working interest owner is also the operator of the property and the non-working interests are part of the same joint operating agreement as the working interests, then income derived form the non-operating interest is not considered passive. Tex. Tax Code §171.0003(b)(2).

V. VALUATION ISSUES FOR MINERAL INTERESTS

A. Governing Law for Valuation Purposes

The rules for valuing minerals for Federal estate and gift tax purposes is, in most respects, similar to those governing the valuation of any other asset; however, there are specific Treasury Regulations addressing the valuation of mineral interests. Those Regulations do no specifically refer to valuation for estate and gift tax purposes, but the concepts are largely the same. Fundamentally, the definition of "fair market value" of a mineral interest is "the amount which would induce a willing seller to sell and a willing buyer to purchase" the interest. Treas. Reg. §1.611-1(d)(2). Those Regulations go on to state that such fair market value must be determined "in light of the conditions and circumstances known at that date, regardless of later discoveries or developments or subsequent improvements in methods of extraction and treatment of the mineral product." Treas. Reg. §1.611-2(d)(1). That language is consistent with and very similar to that language contained in Treas. Reg. §20.2031-1(b), applicable to valuing assets for estate tax purposes, specifically precluding any post-valuation date information.

The Treasury Regulations provides a list of factors that should be considered and given "due weight and consideration." Those factors include: (i) cost, (ii) actual sales and transfers of similar properties, (iii) bona fide offers, (iv) market value of stock or shares, royalties and rentals, (v) valuation for local and state tax purposes, (vi) the amount at which the property may have been inventories in probate proceedings, and (vii) disinterested appraisals by approved methods. Treas. Reg. §1.611-2(d)(1).

Treas. Reg. §1.611-2(d)(2) says "the market approach (comparable transaction) is preferred to the income approach (discounted projected cash flows)." That provision isn't consistent with the current industry practice, which favors the income approach based upon a reserve report.[5]

Often times, a comparable transaction method cannot be used because of the difficulty in finding comparable transaction. That difficulty may arise because of a lack of activity in the subject region. Further, all mineral interests, even in the same region, may not be similar. For example, a subject interest in the liquids rich, core of a new shale play would be substantially different than an interest in the dry gas, outer areas of the same play.

If a comparable transaction approach cannot be used for the reasons cited above, then the income approach may be used. If an income approach is to be used, the value of the expected gross income is to be "reduced to a present value as of the date for which the valuation is made at the rate of interest commensurate with the risk for the operating" life of the interest. Treas. Reg. §1.611-2(e)(2). Thus, the discount rate to be used should take into consideration the riskiness of the subject cash flow stream.

While this paper to this point has considered only the different considerations for the different types of mineral interests (*i.e.*, working interests and royalty interests), it has not considered the nature of the underlying mineral interest itself. If using the income approach, which as noted above is the industry favored approach, the exact nature of the subject mineral interest is critical.

B. Non-Producing Fee Minerals

As noted above, fee simple ownership of land includes the ownership of the minerals as well, unless a legal act has been taken to separate the surface ownership from the mineral ownership. If ownership of the minerals has not been separated from ownership of the surface, those minerals are often owned directly by an individual or through a family entity, along with the surface ownership. Historically, the minerals would not have been valued separately from the surface, particularly in areas where there had not been any significant oil and gas exploration and production activity. With the advent of horizontal drilling and fracking technologies opening up previously undeveloped areas of the country, not valuing the minerals separate from the surface may no longer be a viable alternative. The difficulty in valuing those minerals, however, arises from the fact that there may not be any geological and reservoir data to assess the potential for the minerals.

If ownership of the minerals has been separated from ownership of the surface, but no other action has been taken, ownership of the minerals is referred to as the fee mineral interest, which represents the perpetual ownership of the minerals for the subject property. At that point, the minerals would be classified as non-producing fee minerals.

Whether the minerals have been separated from the land, the best approach for valuing non-producing minerals is a multiple of the price per net mineral acre of a comparable transaction. There are various sources of data from which that information may be obtained.

[5] See Harp, *Oil and Gas Minerals*, Trusts & Estates (October 2012.

C. Working and Royalty Interests

The predominant methodology for valuing working or royalty interests is the income approach. As noted above, the Treasury Regulations, when using the income approach, one important factor is the risk associated with developing and producing the minerals. A typical reserve report will break the mineral into various categories of risk. Starting with least risky are the proved developed producing reserves, referred to as "PDP reserves." Moving up the spectrum of risk are the proved developed nonproducing reserves (the "PDNP reserves") and the proved undeveloped reserves (the "PUD reserves")

VI. FIDUCIARY CONSIDERATIONS ASSOCIATED WITH MINERAL INTERESTS HELD IN TRUST

A. Fiduciary Investment Constraints Arising Under the Uniform Prudent Investor Act

Texas adopted the Uniform Prudent Investor Act in 2003, with an effective date of January 1, 2004. Similarly to the rest of the Trust Code, the Prudent Investor Act sets out the "default" rules, which can be overridden by the language of the trust instrument. The default rules of the Uniform Prudent Investor Act may cause some fiduciary constraints for trusts which will hold exclusively or predominantly mineral interests.

The fundamental standard of the Prudent Investor Act is contained in Tex. Trust Code §117.004, which requires a trustee to "invest and manage trust assets as a prudent investor would, by considering the purposes, terms, distribution requirements, and other circumstances of the trust." That section lists several circumstances which should be taken into consideration when investing and managing the trust assets, including "an asset's special relationship or special value, if any, to the purposes of the trust or to one or more of the beneficiaries." Tex. Trust Code §117.004(b)(8).

Further, Tex. Trust Code §117.005 requires that a "trustee shall diversify the investments of the trust unless the trustee reasonable determines that, because of special circumstances, the purposes of the trust are better served without diversifying."

If a trust is intended to hold only or predominantly mineral interests, that may cause a conflict with the general requirements of Prudent Investor Act, specifically including the duty to diversify contained in Section 117.005. Therefore, it may make sense to include in the administrative provisions of the trust agreement express language overriding the Prudent Investor Act and, specifically, the duty to diversify, as it relates to the mineral interests. Further, it might help alleviate any fiduciary concerns if the preamble to the trust contained an expression that the purposes of the trust are to hold mineral interests. Finally, if the concern is great enough, consider creating the trust in a jurisdiction such as Delaware that has directed trust statutes, which would allow the trustee to act upon directions of an investment advisor for the trust, who could be either the grantor of the trust or someone else with extensive experience with respect to oil and gas properties.

B. Trust Accounting Issues

Along with the adoption of the Prudent Investor Act, Texas also adopted the Uniform Principal and Income Act in 2003, with an effective date of January 1, 2004. Texas, however, made some modifications of the model code provisions, particularly as related to the allocation of oil and gas revenues.

Tex. Trust Code §116.174 contains the general rules for allocation of oil and gas revenues. That section, as related to some of the potential revenue arising from a mineral interest, is very clear cut, but as related to other potential revenue streams is less so.

Under that section, delay rentals and annual rent on a lease are allocated to income, as is any amount received on account of an interest in water that is renewable. A production payment, however, is allocated to income if and to the extent that the agreement creating the payment provides a factor for interest or its equivalent; the balance must be allocated to principal. Tex. Trust Code §116.174(a).

Any other amounts received, whether as a royalty, shut-in well payment, take-or-pay payment, bonus or from water that is not renewable or from a working interest must be allocated between income and principal equitably. Tex. Trust Code §116.174.

That section provides limited guidance on how to determine an equitable allocation. For any trusts that held mineral prior to January 1, 2004, the trustee may make the allocation under the Uniform Prudent Investor Act as adopted or in "any lawful manner used by the trustee before January 1, 2004." Tex. Trust Code §116.174(d). Prior to the adoption of the Uniform Principal and Income Act, the Texas Trust Code relied upon the former rules for depletion allowance under the Internal Revenue Code, which allocated 72.5% to income and 27.5% to principal. See Tex. Prop. Code §113.107 [repealed]. The Texas Trust Code rule continued in existence even after the depletion allowance provisions of the Internal Revenue Code were changed. Thus, a trustee of a trust which held mineral interests prior to January 1, 2004, may continue to rely on the allocation of 72.5% to income and 27.5% to principal.

For any trust that acquired mineral interests only after January 1, 2004, Tex. Trust Code §116.174(e) provides that "[a]n allocation of a receipt under this section is presumed to be equitable if the amount allocated to principal is equal to the amount allowed by the Internal Revenue Code of 1986 as a deduction for depletion of the interest."

The applicable rules for the depletion deduction, which serve as a safe harbor under the Texas Trust Code, are contained in IRC §§611 and 613A. IRC §611 provides scant guidance, as it contains a general rule that a taxpayer is allowed a "reasonable allowance" as a deduction against taxable income. IRC §613A, however, provides more specific guidance. While contained within a complex framework of rules regarding the limitation of the depletion allowance, it generally provides that 15% of receipts related to royalty payments may be allocated to principal and the other 85% may be allocated to income.

The allocation rules contained in the Texas Uniform Principal and Income Act may not be relevant for a majority of trusts. If the terms of the trust give the trustee discretion to distribute income and principal to the beneficiaries, the allocation between income and principal becomes moot. If, however, the trust requires the trustee to distribute all income or gives the trustee only the discretion to distribute all or some portion of the trust income to a beneficiary different than the remainder beneficiary, the issue of allocation remains relevant.

In those circumstances where the distribution provisions of the trust agreement make the allocation between income and principal relevant, an interesting interplay arises between the "equitable allocation" rule of Tex. Trust Code §116.174 and the trustee's power to adjust contained in Tex. Trust Code §116.005. If the trustee is permitted to make an equitable allocation between income and principal, the trustee need not rely on the power to adjust. Conversely, if the trustee has the power to adjust, meeting all of the requirements of Tex. Trust Code §116.005, any allocation under Section 116.174 becomes less meaningful.

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