CURRENT UPDATE ON OIL & GAS VALUATION FOR ESTATE & GIFT TAX PURPOSES

FULL VERSION

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San Antonio Estate Planners Council
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Presented by:
© C. P. Schumann, C.P.A., C.V.A., M.A.F.F.

8535 Wurzbach, Ste. 104
San Antonio, Texas 78240
(210) 736-3955 - 102

BIOGRAPHICAL INFORMATION
C. P. "SALTY" SCHUMANN, C.P.A., C.V.A., M.A.F.F.

C. P. "Salty" Schumann is the managing director and founder of his firm, which offers both traditional accounting services and the non-traditional services of business valuation, litigation, forensic, and oil and gas consulting both on a local and a national level. He is a nationally known speaker and publisher of various articles in the areas in which the firm practices. He holds both the Certified Valuation Analyst and the Master Analyst in Financial Forensic designations from the National Association of Certified Valuators and Analysts (NACVA). He has Federal, District, Bankruptcy and Tax Court Experience .

He was Chair of the NACVA Litigation Forensics Board and the Standards Committee for a number of years. He was also the past Chair of the Texas Society of Certified Public Accountants Litigation Member Services Section. He was also a member of the American Institute of Certified Public Accountants (AICPA) Litigation Support & Dispute Resolution Sub Committee, as well as the AICPA National Litigation Conference Committee and the AICPA Business Valuation Committee.

He has participated in the writing of both the NACVA and AICPA Business Valuation Standards.

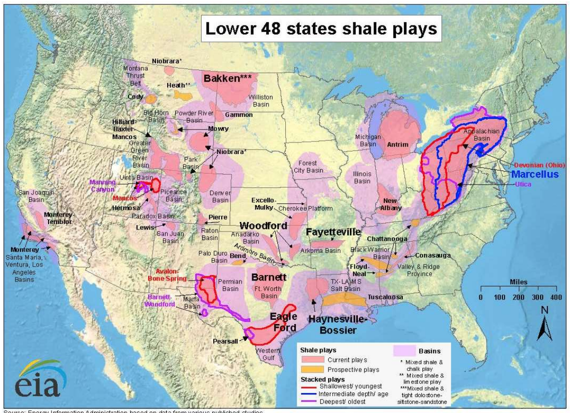
He is currently a member of the Texas Society of CPA's Professional Standards Committee.

BIOGRAPHICAL INFORMATION (Cont.)
C. P. "SALTY" SCHUMANN, C.P.A., C.V.A., M.A.F.F.

His firm has landmen on staff and access to oil & gas information in 42 States in the Continental U.S.

The firm offers the following oil & gas services:

- Mineral and Royalty interest valuation.
- Second opinions on the fair market value of lease offers.
- Litigation - Services.
- Economic Damages.
- Property Tax Protests.
- Estate Planning.
- Computation of Cost Depletion for Tax Purposes.
- Due Diligence, Investment and Merger & Acquisition.
- Petroleum Forensic Document Research.
- Appraisal District Challenge
- Cost Basis Determination For Heirs



Source: Energy Information Administration based on data from various published studies.
Updated: May 9, 2011

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By: David Ammons and James Sheppard

Introduction

Investment decisions in the oil and gas industry are made in a unique environment that is characterized by the following:

- The industry is very cash intensive. The expenditure of millions and sometimes billions of dollars is required for a single project, with no guarantees of success.
- There is frequently a long lead time between initial expenditure and resulting revenue and profitability.
- Decisions are often made in an environment of high levels of uncertainty and—consequently—risk. Common uncertainties include: do hydrocarbons exist beneath the target prospect? Will drilling lead to a blow-out? If we find oil or natural gas reserves will they be smaller than expected or decline faster than geologic conditions suggest? Will crude oil and/or natural gas prices remain strong or nose-dive? Will the applicable regulatory environment change?
- The competition for funds for alternative projects can be substantial.

Given this unique environment, it is critical for oil and gas companies to effectively, efficiently, and accurately evaluate projects before investing substantial sums. Companies employ somewhat different evaluation methods for projects located on land with existing hydrocarbon production than they do for projects located on land with no prior production or exploration. The relevant evaluation methods are discussed in detail in this paper.

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INDUSTRY REFRESHER

1. <u>Categories of Reserves</u>

In general, reserves can be broken down into the following categories: (1) Proved Reserves; (2) Probable Reserves; and (3) Possible Reserves. Moreover, reserves can be classified as either "Developed" or "Undeveloped." Risk is the main differentiating factor between the types of reserve categories and their associated values. Since the value of an asset is a function of its projected future cash flow, the lower the chance of occurrence (actual production), the less valuable the mineral interest.

A. <u>Developed or Undeveloped Reserves</u>

Developed reserves are expected to be recovered from existing wells based upon whether the wells are "producing" or not. Undeveloped reserves are expected to be recovered: (1) from new wells on undrilled acreage; (2) from the deepening of existing wells to a different reservoir; or (3) where a relatively large capital expenditure is required to modify an existing well or to install production or transportation facilities for primary or improved recovery projects.

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INDUSTRY REFRESHER

B. <u>Proved, Probable, or Possible Reserves</u>

Proved reserves are those reserves that geological and engineering data indicate with reasonable certainty are recoverable today, or in the near future, with current technology and under current economic conditions. According to the EIA, which provides statistics for the Department of Energy, the term "reasonable certainty" implies that there is a 90% probability that a company will recover at least the proved reserves estimated to be recoverable.

Probable and possible reserves are further removed from having been tested by the drill bit, and thus, are subject to increasing margins of error. Probable and possible reserves are often referred to as P50 and P10, with probable reserves using a longer-term price assumption and more advanced technology to estimate underground stores.

Probable reserves are "unproved," yet geological and engineering data suggests that they are more likely than not to be recoverable. For example, a "probable" reserve could be proved by normal step-out drilling and infill drilling where data is inadequate to classify them as proved.

Possible reserves are those "unproved" reserves that analysis of geological and engineering data suggests are less likely to be recoverable than probable reserves. For example, possible reserves would lack any adequate definitive data and be referred to as "exploratory."

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DETERMINATION OF FAIR MARKET VALUE OF MINERAL PROPERTIES

What is the Value of the Interest?

IRS Regulation §1.611-2 provides guidance in determining the fair market value of interests in oil, gas, and other natural deposits. The Regulation provides that the comparative value method should be used to determine the fair market value of an oil and gas interest, if at all possible. The use of other methods, such as the "discount cash flow method" should only be used when the comparative method cannot be used.

Comparative Value Method

The "comparative value method" values the interests of similar properties that have been transferred or sold recently. According to Regulation §1.611-2, the due weight and consideration will be given to factors such as:

- cost
- actual sales and transfer of similar properties and improvements
- bona fide offers
- market value of stock or shares
- royalties and rentals
- valuation for local or State taxation
- accounting records of litigation in which the property and improvements may have been inventoried or appraised in probate or similar proceedings
- disinterested appraisals by approved methods

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DETERMINATION OF FAIR MARKET VALUE OF MINERAL PROPERTIES

Often, this type of data is not available. In this case, other methods, such as the present value method, may be used.

Discounted Cash Flow

This method may be used when the value cannot be determined upon the basis of cost or comparative values, or any other method. Factors considered when using the method are: the future price of produced goods and the estimated total future production from the property; the average quality or grade of the mineral reserves; a present value discount and the risks associated with the property (costs of shutting down, dry holes, decrease in production, etc.).

Some have used other, simpler valuation methods, such as a multiple of production over a specified time period. This is not a thorough indicator of fair market value of an interest and may not withstand IRS scrutiny.

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IRS Regulations

26 CFR 1.611-2 - Rules applicable to mines, oil and gas wells, and other natural deposits.

§ 1.611-2 Rules applicable to mines, oil and gas wells, and other natural deposits.

(a) Computation of cost depletion of mines, oil and gas wells, and other natural deposits.

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(1) The basis upon which cost depletion is to be allowed in respect of any mineral property is the basis provided for in section 612 and the regulations thereunder. After the amount of such basis applicable to the mineral property has been determined for the taxable year, the cost depletion for that year shall be computed by dividing such amount by the number of units of mineral remaining as of the taxable year (see subparagraph (3) of this paragraph), and by multiplying the depletion unit, so determined, by the number of units of mineral sold within the taxable year (see subparagraph (2) of this paragraph). In the selection of a unit of mineral for depletion, preference shall be given to the principal or customary unit or units paid for in the products sold, such as tons of ore, barrels of oil, or thousands of cubic feet of natural gas.

(2) As used in this paragraph, the phrase ***number of units sold within the taxable year:***

(i) In the case of a taxpayer reporting income on the cash receipts and disbursements method, includes units for which payments were received within the taxable year although produced or sold prior to the taxable year, and excludes units sold but not paid for in the taxable year, and

(ii) In the case of a taxpayer reporting income on the accrual method, shall be determined from the taxpayer's inventories kept in physical quantities and in a manner consistent with his method of inventory accounting under section 471 or 472

The phrase does not include units with respect to which depletion deductions were allowed or allowable prior to the taxable year.

(3) ***The number of units of mineral remaining as of the taxable year*** is the number of units of mineral remaining at the end of the year to be recovered from the property (including units recovered but not sold) plus the *number of units sold within the taxable year* as defined in this section.

(4) In the case of a natural gas well where the annual production is not metered and is not capable of being estimated with reasonable accuracy, the taxpayer may compute the cost depletion allowance in respect of such property for the taxable year by multiplying the adjusted basis of the property by a fraction, the numerator of which is equal to the decline in rock pressure during the taxable year and the denominator of which is equal to the expected total decline in rock pressure from the beginning of the taxable year to the economic limit of production. Taxpayers computing depletion by this method must keep accurate records of periodical pressure determinations.

(5) If an aggregation of two or more separate mineral properties is made during a taxable year under section 614, cost depletion for each such property shall be computed separately for that portion of the taxable year ending immediately before the effective date of the aggregation. Cost depletion with respect to the aggregated property shall be computed for that portion of the taxable year beginning on such effective date. The allowance for cost depletion for the taxable year shall be the sum of such cost depletion computations. For purposes of this paragraph, each such portion of the taxable year shall be considered as a taxable year. Similar rules shall be applied where a separate mineral property is properly removed from an existing aggregation during a taxable year. See section 614 and the regulations thereunder for rules relating to the effective date of an aggregation of mineral interests and for rules relating to the adjusted basis of an aggregation.

(6) The apportionment of the deduction among the several owners of economic interests in the mineral deposit or deposits will be made as provided in paragraph (c) of § 1.611-1.

(b) *Depletion accounts of mineral property.*

(1) Every taxpayer claiming and making a deduction for depletion of mineral property shall keep a separate account in which shall be accurately recorded the cost or other basis provided by section 1012, of such property together with subsequent allowable capital additions to each account and all the other adjustments required by section 1016.

(2) Mineral property accounts shall thereafter be credited annually with the amounts of the depletion so computed in accordance with section 611 or 613 and the regulations thereunder; or the amounts of the depletion computed in shall be credited to depletion reserve accounts. No further deductions for cost depletion shall be allowed when the sum of the credits for depletion equals the cost or other basis of the property, plus allowable capital additions. However, depletion deductions may be allowable thereafter computed upon a percentage of gross income from the property. See section 613 and the regulations thereunder. In no event shall percentage depletion in excess of cost or other basis of the property be credited to the improvements account or the depreciation reserve account.

(c) *Determination of mineral contents of deposits.*

(1) If it is necessary to estimate or determine with respect to any mineral deposit as of any specific date the total recoverable units (tons, pounds, ounces, barrels, thousands of cubic feet, or other measure) of mineral products reasonably known, or on good evidence believed, to have existed in place as of that date, the estimate or determination must be made according to the method current in the industry and in the light of the most accurate and reliable information obtainable. In the selection of a unit of estimate, preference shall be given to the principal unit (or units) paid for in the product marketed. The estimate of the recoverable units of the mineral products in the deposit for the purposes of valuation and depletion shall include as to both quantity and grade:

(i) The ores and mineralsin sight, *blocked out, developed,* or *assured,* in the usual or conventional meaning of these terms with respect to the type of the deposits, and

(ii) ***Probable*** or *prospective* ores or minerals (in the corresponding sense), that is, ores or minerals that are believed to exist on the basis of good evidence although not actually known to occur on the basis of existing development. Such *probable* or *prospective* ores or minerals may be estimated:

(a) As to quantity, only in case they are extensions of known deposits or are new bodies or masses whose existence is indicated by geological surveys or other evidence to a high degree of probability, and

(b) As to grade, only in accordance with the best indications available as to richness.

(2) If the number of recoverable units of mineral in the deposit has been previously estimated for the prior year or years, and if there has been no known change in the facts upon which the prior estimate was based, the number of recoverable units of mineral in the deposit as of the taxable year will be the number remaining from the prior estimate. However, for any taxable year for which it is ascertained either by the taxpayer or the

district director from any source, such as operations or development work prior to the close of the taxable year, that the remaining recoverable mineral units as of the taxable year are materially greater or less than the number remaining from the prior estimate, then the estimate of the remaining recoverable units shall be revised, and the annual cost depletion allowance with respect to the property for the taxable year and for subsequent taxable years will be based upon the revised estimate until a change in the facts requires another revision. Such revised estimate will not, however, change the adjusted basis for depletion.

(d) *Determination of fair market value of mineral properties, and improvements, if any.*

(1) If the fair market value of the mineral property and improvements at a specified date is to be determined for the purpose of ascertaining the basis, such value must be determined, subject to approval or revision by the district director, by the owner of such property and improvements in the 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. The district director will give due weight and consideration to any and all factors and evidence having a bearing on the market value, such as cost, actual sales and transfers of similar properties and improvements, bona fide offers, market value of stock or shares, royalties and rentals, valuation for local or State taxation, partnership accountings, records of litigation in which the value of the property and improvements was in question, the amount at which the property and improvements may have been inventoried or appraised in probate or similar proceedings, and disinterested appraisals by approved methods.

(2) If the fair market value must be ascertained as of a certain date, analytical appraisal methods of valuation, such as the present value method will not be used:

(i) If the value of a mineral property and improvements, if any, can be determined upon the basis of cost or comparative values and replacement value of equipment, or

(ii) If the fair market value can reasonably be determined by any other method.

(e) *Determination of the fair market value of mineral property by the present value method.*

(1) To determine the fair market value of a mineral property and improvements by the present value method, the essential factors must be determined for each mineral deposit. The essential factors in determining the fair market value of mineral deposits are:

(i) The total quantity of mineral in terms of the principal or customary unit (or units) paid for in the product marketed,

(ii) The quantity of mineral expected to be recovered during each operating period,

(iii) The average quality or grade of the mineral reserves,

(iv) The allocation of the total expected profit to the several processes or operations necessary for the preparation of the mineral for market,

(v) The probable operating life of the deposit in years,

(vi) The development cost,

(vii) The operating cost,

(viii) The total expected profit,

(ix) The rate at which this profit will be obtained, and

(x) The rate of interest commensurate with the risk for the particular deposit.

(2) If the mineral deposit has been sufficiently developed, the valuation factors specified in subparagraph (1) of this paragraph may be determined from past operating experience. In the application of factors derived from past experience, full allowance should be made for probable future variations in the rate of exhaustion, quality or grade of the mineral, percentage of recovery, cost of development, production, interest rate, and selling price of the product marketed during the expected operating life of the mineral deposit. Mineral deposits for which these factors cannot be determined with reasonable accuracy from past operating experience may also be valued by the present value method; but the factors must be deduced from concurrent evidence, such as the general type of the deposit, the characteristics of the district in which it occurs, the habit of the mineral deposits, the intensity of mineralization, the oil-gas ratio, the rate at which additional mineral has been disclosed by exploitation, the stage of the operating life of the deposit, and any other evidence tending to establish a reasonable estimate of the required factors.

(3) Mineral deposits of different grades, locations, and probable dates of extraction should be valued separately. The mineral content of a deposit shall be determined in accordance with paragraph (c) of this section. In estimating the average grade of the developed and prospective mineral, account should be taken of probable increases or decreases as indicated by the operating history. The rate of exhaustion of a mineral deposit should be determined with due regard to the limitations imposed by plant capacity, by the character of the deposit, by the ability to market the mineral product, by labor conditions, and by the operating program in force or reasonably to be expected for future operations. The operating life of a mineral deposit is that number of years necessary for the exhaustion of both the developed and prospective mineral content at the rate determined as above. The operating life of oil and gas wells is also influenced by the natural decline in pressure and flow, and by voluntary or enforced curtailment of production. The operating cost includes all current expense of producing, preparing, and marketing the mineral product sold (due consideration being given to taxes) exclusive of allowable capital additions, as described in §§ 1.612-2 and 1.612-4, and deductions for depreciation and depletion, but including cost of repairs. This cost of repairs is not to be confused with the depreciation deduction by which the cost of improvements is returned to the taxpayer free from tax. In general, no estimates of these factors will be approved by the district director which are not supported by the operating experience of the property or which are derived from different and arbitrarily selected periods.

(4) The value of each mineral deposit is measured by the expected gross income (the number of units of mineral recoverable in marketable form multiplied by the estimated market price per unit) less the estimated operating cost, 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, and further reduced by the value at that date of the improvements and of the capital additions, if any, necessary to realize the profits. The degree of risk is

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generally lowest in cases where the factors of valuation are fully supported by the operating record of the mineral enterprise before the date for which the valuation is made. On the other hand, higher risks ordinarily attach to appraisals upon any other basis.

(f) ***Revaluation of mineral property not allowed.*** No revaluation of a mineral property whose value as of any specific date has been determined and approved will be made or allowed during the continuance of the ownership under which the value was so determined and approved, except in the case of misrepresentation or fraud or gross error as to any facts known on the date as of which the valuation was made. Revaluation on account of misrepresentation or fraud or such gross error will be made only with the written approval of the Commissioner.

(g) ***Statement to be attached to return when valuation, depletion, or depreciation of mineral property or improvements are claimed.***

(1) For the first taxable year ending before December 31, 1967, for which a taxpayer asserts a value for any mineral property or improvement as of a specific date or claims a deduction for depletion, or depreciation, there shall be attached to the return of the taxpayer for such taxable year a statement setting forth, in complete, summary form, the pertinent information required by this paragraph with respect to each such mineral property or improvement (including oil and gas properties or improvements). The summary statement shall be deemed a part of the income tax return to which it relates. In addition to such summary statement, the taxpayer must assemble, segregate and have readily available at his principal place of business, all the supporting data (listed in subparagraphs (2), (3), and (4) of this paragraph) which is used in compiling the summary statement. For taxable years after such first taxable year, and ending before December 31, 1967, the taxpayer need attach to his return only an explanation of the changes, if any, in the information previously furnished. For example, when a taxpayer has filed adequate maps with the district director he may be relieved of filing further maps of the same area, if all additional information necessary for keeping the maps up-to-date is filed each year. In any case in which any of the information required by this paragraph has been previously filed by the taxpayer (including information furnished in accordance with corresponding provisions of prior regulations), such information need not be filed again, but a statement should be attached to the return of the taxpayer indicating clearly when and in what form such information was previously filed. For provisions relating to the data which shall be submitted with returns for taxable years ending on or after December 31, 1967, see subparagraph (5) of this paragraph.

(2) The information referred to in subparagraph (1) of this paragraph is as follows:

(i) An adequate map showing the name, description, location, date of surveys, and identification of the deposit or deposits;

(ii) A description of the character of the taxpayer's property, accompanied by a copy of the instrument or instruments by which it was acquired;

(iii) The date of acquisition of the property, the exact terms and dates of expiration of all leases involved, and if terminated, the reasons therefor;

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(iv) The cost of the mineral property and improvements, stating the amount paid to each vendor, with his name and address;

(v) The date as of which the mineral property and improvements are valued, if a valuation is necessary to establish the basis as provided by section 1012;

(vi) The value of the mineral property and improvements on that date with a statement of the precise method by which it was determined;

(vii) An allocation of the cost or value among the mineral property, improvements and the surface of the land for purposes other than mineral production;

(viii) The estimated number of units of each kind of mineral at the end of the taxable year, and also at the date of acquisition, if acquired during the taxable year or at the date as of which any valuation is made, together with an explanation of the method used in the estimation, the name and address of the person making the estimate, and an average analysis which will indicate the quality of the mineral valued, including the grade or gravity in the case of oil;

(ix) The number of units sold and the number of units for which payment was received or accrued during the year for which the return is made (in the case of newly developed oil and gas deposits it is desirable that this information be furnished by months);

(x) The gross amount received from the sale of mineral;

(xi) The amount of depreciation for the taxable year and the amount of cost depletion for the taxable year;

(xii) The amounts of depletion and depreciation, if any, stated separately, which for each and every prior year:

(a) Were allowed (see section 1016(a)(2)),

(b) Were allowable, and

(c) Would have been allowable without reference to percentage or discovery depletion;

(xiii) The fractions (however measured) of gross production from the deposit or deposits to which the taxpayer and other persons are entitled together with the names and addresses of such other persons; and

(xiv) Any other data which will be helpful in determining the reasonableness of the valuation asserted or of the deductions claimed.

(3) In the case of oil and gas properties, the following information with respect to each property is required in addition to that information set forth in subparagraph (2) of this paragraph:

(i) The number of acres of producing oil or gas land and, if additional acreage is claimed to be proven, the amount of such acreage and the reasons for believing it to be proven;

(ii) The number of wells producing at the beginning and end of the taxable year;

(iii) The date of completion of each well finished during the taxable year;

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12/11/2017 26 CFR 1.611-2 - Rules applicable to mines, oil and gas wells, and other natural deposits. | US Law | LII / Legal Information Institute

(iv) The date of abandonment of each well abandoned during the taxable year;

(v) Maps showing the location of the tracts or leases and of the producing and abandoned wells, dry holes, and proven oil and gas lands (the maps should show depth, initial production, and date of completion of each well, etc., to the extent that these data are available);

(vi) The number of pay sands and average thickness of each pay sand or zone;

(vii) The average depth to the top of each of the different pay sands;

(viii) The annual production of the deposit or of the individual wells, if the latter information is available, from the beginning of its productivity to the end of the taxable year, the average number of wells producing during each year, and the initial daily production of each well (the extent to which oil or gas is used for fuel on the premises should be stated with reasonable accuracy);

(ix) All available data regarding change in operating conditions, such as unit operation, proration, flooding, use of air-gas lift, vacuum, shooting, and similar information, which have a direct effect on the production of the deposit; and

(x) Available geological information having a probable bearing on the oil and gas content; information with respect to edge water, water drive, bottom hole pressures, oil-gas ratio, porosity of reservoir rock, percentage of recovery, expected date of cessation of natural flow, decline in estimated potential, and characteristics similar to characteristics of other known fields.

(4) For rules relating to an additional statement to be attached to the return when the depletion deduction is computed upon a percentage of gross income from the property, see § 1.613-6.

(5) A taxpayer who claims a total deduction of more than $200 for depletion of mines, oil and gas wells, or other natural deposits for the taxable year ending on or after December 31, 1967, and before December 31, 1968, shall submit with his return for such taxable year a filled-out Form M (Mines and Other Natural Deposits - Depletion Data) or Form O (Oil and Gas Depletion Data). See section 6011(a). For the purpose of this subparagraph, the determination under section 631(c) of gain or loss upon the disposition of coal or domestic iron ore with a retained economic interest shall not be regarded as the claiming of a deduction for depletion. Such forms shall be filed for any subsequent taxable year if the Commissioner determines that the forms are required for such year. Where appropriate, both Form M and Form O shall be filed. Forms M and O shall be deemed to be part of the return to which they relate. If a taxpayer mines more than one mineral, a separate Form M shall be filed for each such mineral. If a taxpayer has both domestic and foreign properties, separate forms shall be filed for each country in which a taxpayer's properties are located. All data relating to a taxpayer's domestic oil and gas properties shall be summarized on a single Form O, and data relating to a taxpayer's domestic mineral properties (other than oil and gas properties) shall be summarized on a single Form M for each mineral. Similarly, all data relating to a taxpayer's oil and gas properties in a specific foreign country shall be summarized on a single Form O, and data relating to a taxpayer's mineral properties (other than oil and gas properties) in a specific foreign country shall be summarized on a single

https://www.law.cornell.edu/cfr/text/26/1.611-2

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Form M for each mineral. In addition, the taxpayer shall assemble, segregate, and have readily available at his principal place of business, the data listed in subparagraphs (2), (3), and (4) of this paragraph.

[T.D. 6500, 25 FR 11737, Nov. 26, 1960, as amended by T.D. 6936, 32 FR 17518, Dec. 7, 1967; T.D. 7170, 37 FR 5373, Mar. 15, 1972]

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Tax Court Cases on Valuing Mineral Interests

Most Tax Court Cases are fact specific and date back 40-years or so. The author maintains a library of such and are available upon request.

However, none are fact specific and provide little guidance concerning how to value.

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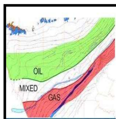



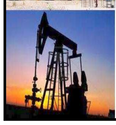

What's New From The IRS Regarding Valuation

This was issued in response to valuation of non cash property for donation purposes.

Definition of Appraisal - Adequate Disclosure Regs
"Appraisal" (as defined by the Internal Revenue Service in Notice 2006-96), means a written valuation report, signed and dated by a qualified appraiser in accordance with generally accepted appraisal standards and containing the following information:

- Includes certain information, such as a property description, Fair Market Value of an ownership interest, appraiser identification information, date of valuation and valuation methods employed; and
- Relates to an appraisal made not earlier than 60 days before the date of contribution of the appraised property; and
- Does not involve a contingent appraisal fee; and
- Meets the other relevant requirements of Regulations Section 1.170A-13(c)(3); and
- Notice 2006-96, 2006-46 I.R.B. 902.

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Definition of Appraiser

"Appraiser" (as defined by the Internal Revenue Service in Notice 2006-96), means a person or firm qualified to perform business "Appraisals" of partnerships and ownership interests in partnerships and has been certified with an appraisal designation from a recognized professional appraisal organization (such as the National Association of Certified Valuators and Analysts (NACVA), the Appraisal Institute, ASFMRA, NAIFA, ASA, etc.), or has met certain minimum education and experience requirements; and

- Regularly prepares appraisals for which the individual is paid; and
- Demonstrates verifiable education and experience in valuing the type of property being appraised; and
- Has not been prohibited from practicing before the IRS under Section 330(c) of Title 31 of the United States Code at any time during the three-year period ending on the date of the appraisal; and
- Is not an excluded individual (someone who is the donor or recipient of the property).

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Adequate Disclosure Items Related to the Valuation Report

- The date of the appraisal.
- The date of the transfer.
- The purpose of the appraisal.
- A description of the property.
- A description of the appraisal process employed, including the valuation method(s) utilized.
- A description of any hypothetical conditions considered.
- The information considered in determining the value, including all financial information in sufficient detail to allow the reader to replicate the appraisal analysis and valuation.
- The appraisal procedures followed, and the reason that support the analysis, opinions, and conclusions.
- The valuation method utilized, the rationale for the procedure used in determining the fair market value of the asset transferred.
- The specific basis for the valuation, such as specific comparable sales or transactions, sales of similar interests, asset-based approaches, merger-acquisition transactions, etc.
- Descriptions of any restrictions or other limiting conditions present.
- Certifications and representations of the Analyst.

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MSSP

Market Segment Specialization Program

Oil and Gas Industry

The taxpayer names and addresses shown in this publication are hypothetical. They were chosen at random from a list of names of American colleges and universities as shown in Webster's Dictionary or from a list of names of counties in the United States as listed in the United States Government Printing Office Style Manual.

This material was designed specifically for training purposes only. Under no circumstances should the contents be used or cited as authority for setting or sustaining a technical position.

Department of the Treasury
Internal Revenue Service

Training 3149-125 (5/96)
TPDS No. 84212C

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4.48.4.2.2 (07-01-2006)
Identifying

In developing a valuation conclusion, valuators should define the assignment and determine the scope of work necessary by identifying the following:

A. Property to be valued
B. Interest to be valued
C. Effective valuation date
D. Purpose of valuation
E. Use of valuation
F. Statement of value
G. Standard and definition of value
H. Assumptions
I. Limiting conditions
J. Scope limitations
K. Restrictions, agreements and other factors that may influence value
L. Sources of information

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Part 4. Examining Process
Chapter 41. Oil and Gas Industry
Section 1. Oil and Gas Handbook

4.41.1 Oil and Gas Handbook

4.41.1.1 Overview of Oil and Gas Handbook
4.41.1.2 Acquisitions

4.41.1.1 (07-31-2002)
Overview of Oil and Gas Handbook

1. This handbook introduces the guidelines for the examination of income tax returns of taxpayers involved in the oil and gas industry.
2. These guidelines have been prepared to assist examiners in the examination of income tax returns of taxpayers involved in the oil and gas industry.
3. Diligent use of these guidelines will shorten the time needed to acquire the examination skills essential to this specialty. Nothing contained herein should discourage examiners from improving upon these techniques or from exercising their own initiative and ingenuity.
4. Authoritative reference material is shown in Exhibit *4.41.1-1* for the reader who may want additional research material. The list will also be useful to a reader who may desire to further his/her study in oil and gas taxation. While the reference material listed is not an exhaustive list, it will provide the reader with excellent research tools.
5. See Exhibit 4.41.1-9 for items to consider during preparation of Forms 4318, 4764, 4764-Bs and 886-As.

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4.48.4.2.3 (07-01-2006)
Analyzing

1. In developing a valuation conclusion, valuators should analyze the relevant information necessary to accomplish the assignment including:
   - The nature of the business and the history of the enterprise from its inception
   - The economic outlook in general and the condition and outlook of the specific industry in particular
   - The book value of the stock or interest and the financial condition of the business
   - The earning capacity of the company
   - The dividend-paying capacity
   - Existence or non existence of goodwill or other intangible value
   - Sales of the stock or interest and the size of the block of stock to be valued
   - The market price of stocks or interests of corporations or entities engaged in the same or a similar line of business having their stocks or interests actively traded in a free and open market, either on an exchange or over-the-counter
   - Other relevant information

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IRS Oversight of Valuation Services

With the enactment of Sec. 6695A, in 2006 the IRS was given new responsibilities to ensure the quality of appraisals and appraisers who provided information in support of a taxpayer's federal tax filings.

The original purpose of Sec. 6695A was to stop perceived abuse in real estate easement appraisals for charitable deductions. It was later explicitly extended to include business appraisals for estate and gift tax purposes.

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IRS Appraisal Review Process

The Sec. 6695A appraisal review process was developed after open forum discussions in 2010 with representatives from appraisal organizations, including representatives of the AICPA.

Under the Sec. 6695A review process, all estate and gift valuations are sent to one of two central locations where estate and gift tax attorneys and IRS engineer specialists perform an initial national classification process. Both tax returns with and without attached appraisals may be referred to estate and gift tax attorney groups at local IRS offices for further classification. After classification of the case at the local level, an estate and gift tax attorney may open the return for an examination. After the return and any valuation on the return have been analyzed, the IRS may impose a Sec. 6695A penalty.

An appraisal examination can also be initiated by an IRS revenue agent. While the revenue agent's primary focus will be the taxpayer and a potential tax deficiency, rather than the appraiser, the revenue agent may decide to initiate a Sec. 6695A process. At this point, the process also should involve an IRS engineer.

If the IRS engineer believes that the "correct value" of the interest being appraised differs from the appraised value and that the appraiser has not complied with his or her organization's standards, the review process may proceed and may ultimately lead to appraisal penalties under Sec. 6695A and a possible referral to the OPR, which is charged with ensuring that practitioners adhere to professional standards and follow the law.

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THE RESERVE APPRAISAL

Classification of Reserve Method For Determining Fair Market Value

The starting point for any valuation estimate determined by a reserve report is the petroleum engineer who must estimate the quantity and nature of hydrocarbons in the ground, how quickly they can be recovered, what percentage can be recovered, the cost of recovery, and the present value of the net cash flow using various discount rates, usually centering on 10%, before tax (PV10 method).

In the reserve report, the petroleum engineer (usually a reservoir engineer) should estimate, based on the best data available, the classification and quantity of reserves that can be recovered over time. Typically, the reservoir engineer will apply assumed prices into the future in order to "monetize" those reserves into a cash flow table. The engineer may or may not be qualified to opine as to the likelihood and reasonableness of the pricing assumptions: often the engineer simply uses the pricing assumptions requested by the client.

Classification of Reserves
In estimating reserves, the reservoir engineer should give quantities of recoverable reserves within various classifications, generally proved, probable and possible.

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In laymen's terms, the categories of reserves are as follows:

1. ***Proved developed producing*** **("PDP")** reserves are those where the well is completed and the reserves are currently being produced. This is the most valuable category because (1) pressure and production data are readily available and generally accurate, and (2) cash is being generated regularly by production. The amount is typically 90% - 100% of discounted future net income.
2. ***Proved developed non-producing*** **("PDNP")** are reserves where the well-bore exists and the reserves are identified, but for some reason are not currently producing, whether shut-in for lack of market or for mechanical reasons. In this category, the reserves can be produced by either turning on production or accomplishing a mechanical repair operation. The significance of this category is that no additional capital expenditure is required to complete a new formation, and thus, there is less risk than in proved behind-pipe. This amount is typically 50% to 80% of discounted future income.
3. ***Proved behind-pipe*** **("PBP")** reserves are those where a reservoir different from one currently producing has been identified. However, because the operator must plug off the current zone and recomplete in a different zone (usually higher up, *i.e.*, closer to the surface), there is greater risk that the reserves may not be recoverable.

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4. ***Proved undeveloped*** **("PUD")** are the lowest category of proved reserves and the least valuable because a new well is required to be drilled and completed, with accompanying risk, in order to recover the value. These reserves require the most capital investment and the greatest risk (among proved reserves) in order to exploit them. This amount is less than 50% of future cash flow. The definitions of proved reserves are established by the Society of Petroleum Engineers, the World Petroleum Congress, the American Association of Petroleum Geologists, the American Petroleum Institute, and the Society of Petroleum Evaluation Engineers. The Securities and Exchange Commission has its own set of definitions, though the only essential difference is that of holding prices constant (no increase based on estimated future conditions), but allowing escalation of prices based upon existing contracts, if any.
5. Due to the availability of oil & gas production software it is now feasible to develop decline curves when a reserve report has not been completed.
6. PV10 is the present value of estimated future oil and gas revenues, net of estimated direct expenses, discounted at annual discount rate of 10%. This nomenclature is most commonly used in the energy industry, and is used to estimate the present value of a company's proved oil and gas reserves.

It is extremely important for professionals dealing with reserve reports to recognize that they are not a determination of fair market value. Although Generally Accepted Accounting Principles, as modified by the SEC rules, require companies to report reserves based on the lower of cost or present value of proved reserves, it is essential to understand that the process is not a Conclusion of Value.

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There are three common methods for converting a reserve report to FMV:

1. Perhaps the most accurate, but admittedly anecdotal, approach is to interview or survey investment bankers or property brokers in the oil and gas acquisition and divestiture (A&D) market regarding discount rates in effect at the valuation date. Discount rates are dependent on reserve category, location product type (oil versus gas) and size of transaction. For example, an A&D firm might show statistics indicating that oil weighted Permian Basin PDP properties were transacting at PV-7 near the valuation date.
2. Another approach involves using data contained in an annual survey (the SPEE survey) conducted by the Society of Petroleum Evaluation Engineers. The SPEE survey polls about 100 experienced PEs and other experts who work in the context of A&D transactions. The section of the survey most commonly cited deals with risk adjustment factors (RAFs) used for acquisitions. The RAF isn't a discount rate in the traditional sense, as used in the first method, but rather a "haircut" factor. While this methodology is simple, and the valuation conclusion is clear (and presumably defensible), it can be overused as a onesize-fits-all solution. For example, I interviewed an active property buyer in the Gulf of Mexico recently and found that use of the SPEE RAFs, without any further adjustment, would have significantly overvalued the offshore properties.

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There are three common methods for converting a reserve report to FMV:

3. Another source for the build up of the discount rate is the cost of capital for publicly traded guideline companies. The reserve base of the guideline public companies should be sufficiently comparable to the subject properties, particularly the ratios of PDP and PUD reserves to total reserves. This approach requires a number of adjustments to reflect the public companies' general and administrative cost structure, growth profile and marketability, which aren't characteristics of the subject static oil and gas reserve base.

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The Methods of Determining Fair Market Value.

There are four basic methods of determining FMV of an oil and gas property: (1) comparative sales; (2) rule of thumb; (3) income forecast, and (4) replacement cost. The SPEE 2001 Survey inquired, for the first time, as to the respondents' preferred method for determining value of oil and gas properties. In the response, the Discounted Cash Flow method (which is a subset of the income forecast as described by Garb) was the overwhelming favorite, at 86%. Comparable sales was preferred by 1%, and no other got more than 5% preference.

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Rules of Thumb

The various rule of thumb methods have merit but do not consider the length of time during which revenue will flow from the investment.

The four most familiar rule of thumb methods are: (1) price paid per barrel equivalent of reserves; (2) price paid per equivalent barrel per day of producing rate; (3) profit to investment ratio; and (4) current income rate for a specific period of time. These methods do not require sophisticated reserve studies and are easy to calculate. However, they do not measure the maximum negative cash position that the purchaser will experience. Also, these tests do not consider market uncertainties, nor time (and thus favor long lived properties).

Other Thoughts

- **Minerals not producing.... therefore minerals have no value?**
- **2-3x annualized cash flow (not 4x or 5x)**
  - **Typically, used for producing properties and often used for IRS purposes.**
  - **Mineral packages that are producing, diversified and have shallow decline rates (favorable reserve replacement ratios) or upside potential can sell at 10x historical cash flow, or a future of 3 - 6.5 or 1.5 to 3.0 times the lease bonus.**
- **Cost approach is never applicable**
- Non-producing minerals (this rule of thumb presumably applies to both leased and unleased minerals) valued at the going lease bonus rate x 2 to 3 of adjacent properties as of valuation date.

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Comparative Value Method

The "comparative value method" values the interests of similar properties that have been transferred or recently sold. According to Regulation §1.611-2, due weight and consideration will be given to factors such as:

Cost
Actual sales and transfer of similar properties and improvements
Bona fide offers
Market value of stock or shares
Royalties and rentals
Valuation for local or State taxation
Accounting records of litigation in which the property improvements may have been inventoried or appraised in probate or similar proceedings
Disinterested appraisals by approved methods

Relationship Between Lease Bonus and Mineral Rights Value

The Lease Bonus method for conventional oil & gas mineral rights has been observed in the market and in literature since the 1990's and possibly earlier. In its simplest form it provides an estimate of the Fair Market Value of a landowner's oil & gas mineral estate under the assumption that the *Highest & Best Use* is for the leasing and exploration for oil & gas. The Lease Bonus method is therefore applicable during the early stages of an oil & gas play.

The method is reliable when lease terms such as front-end bonus, annual rentals or paid-up bonus, primary term and royalty rate are reasonably uniform in an area. When applied to conventional oil and gas plays with a distinct petroleum system (separate source rock, reservoir rock, etc.), the fair market value of unleased oil & gas rights is reliably estimated by multiplying the current lease bonus amount in dollars per net mineral acre by a factor of from 2 ½ to 3.

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Lease Bonus Method for Unconventional Oil & Gas Rights

The unconventional oil & gas mineral rights include those that are being produced from horizontally drilled wells in shale formations. A change in the relationship between the bonus (now a larger paid-up-bonus) and the fair market value of the oil & gas mineral rights has been noted in the market. The multiplier is now 2 times the bonus amount to estimate the fair market value of the minerals of early-stage acreage.

In short, the oil companies need the acreage and will pay. Likewise, the landowners also want more money up front. A landowner knows that just leasing his land to an oil company does not guarantee drilling and royalty income from production, not to mention the numerous development activities, which must precede royalty payment. The landowner will therefore insist on more money up front instead of waiting for the uncertain royalty.

The combination of market factors leads to larger bonus payments for the unconventional oil & gas leases. And with larger bonus payments it follows that the multiplier with which to estimate the fair market value of the actual oil & gas mineral interest at these early stages will be smaller. Examples have been observed from the market where the leasing oil company has offered a landowner to choose between one bonus amount for a lease and the double amount for outright sale of his mineral rights. Thus, the fair market value for the latter would equal 2 times the offered bonus.

It is noted that the fair market value of the mineral rights is arrived at by a much higher multiple of the offered lease bonus than observed for early exploration leases. An offer for Niobrara shale acreage in Colorado gave a choice to the landowner between $500 per net acre as a lease bonus for a 3/16th royalty lease versus $1,900 for outright purchase of the mineral estate. That is a multiplier of 3.8. In this case the local area had already seen Niobrara testing and development and the operator had commenced construction of a horizontal drilling and multiple-well production pad.

In conclusion, the lease bonus approach is reliable for both conventional and for unconventional oil & gas mineral rights as long as the acreage use is in the early exploration states. At later stages and among producing properties any unleased acreage may be worth 3 to 4 times the bonus offered. A more reliable method may be to run a discounted cash flow model, calculate a Net Present Value for the royalty stream and risk it by a probability factor for coming about at the predicted quantify and commodity price in the near future.

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SUBSEQUENT EVENTS

Federal tax valuation matters are based on the fair market value standard of value. The definition of fair market value has generally been interpreted to be based only on information that was known or knowable as of the valuation date.

A subsequent event is defined as an event that occurs after the valuation date. A majority of U.S. Tax Court cases dealing with subsequent events have concluded that it is inappropriate to use hindsight as direct evidence of value as of the valuation date. However, the Tax Court has also found that certain subsequent events that occur within a reasonable time after the valuation date may be appropriate to consider in the determination of fair market value.

1. **Subsequent events that were reasonably foreseeable by a hypothetical buyer or seller as of the valuation date.** For example, in the *Trust Services* decision,5 the 9th Circuit Court stated that subsequent events are not considered to fix fair market value, except to the extent that they were reasonably foreseeable at the date of valuation.

2. **Subsequent events that prove the reasonableness of expectations of a hypothetical buyer or seller as of the valuation date.** For example, in the *O'Reilly* decision, the Tax Court relied on dividends actually paid after the valuation date to corroborate an expert's projected dividends.

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SUBSEQUENT EVENTS Cont.

3. **The subsequent sale of the subject ownership interest.** For example, in the *Scanlan* decision, the Tax Court stated, "The best indicator of the value of unlisted stock often is arm's-length sales of that stock at or around the time of valuation" despite the fact that the stock redemption occurred more than 2 years from the valuation date. In addition, in the *Hillebrandt* decision, the Tax Court held that a sale of property after the date of death may be considered evidence of the property's value at the date of death so long as it occurs within a reasonable time after death and intervening events have not changed the value of the property.

4. **The subsequent sale of comparable ownership interests.** For example, in the *Thompson* decision, the Tax Court stated "if comparable sales occur after the death of decedent, there is no sound reason to ignore them."

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SUBSEQUENT EVENTS Cont.

In addition, the Tax Court has opined that when a subsequent sale is relied on in the estimation of the fair market value, it is necessary to adjust the subsequent sale price for events between the valuation date and the subsequent sale date that affect the subsequent sale price.

For example, in the *Noble* decision, the Tax Court stated:

When a subsequent event is used to set the fair market value of property as of an earlier date . . . adjustments should be made to the sale price to account for happenings between the two dates which would affect the later sale price; these happenings include (1) inflation, (2) changes in the relevant industry and the expectations for that industry, (3) changes in business component results, (4) changes in technology, macroeconomics, or tax law, and (5) the occurrence or nonoccurrence of any event which a hypothetical reasonable buyer or a hypothetical reasonable seller would conclude would affect the selling price of the property subject to valuation (e.g., the death of a key employee).

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SUBSEQUENT EVENTS Cont.

Summary

- While in theory any subsequent event should not impact valuation, the IRS often will try to use subsequent events as corroborating evidence for its position.
- Therefore, it may be helpful to be prepared to reconcile the valuation to subsequent events.
- A majority of the federal tax cases dealing with subsequent events have concluded that it is inappropriate to use hindsight as direct evidence of value as of the valuation date.
- However, the Tax Court (and other federal courts) has also opined that certain subsequent events that occur within a reasonable time after the valuation date may be appropriate to considered:
  - Reasonable foreseeable
  - Prove reasonableness of expectations
  - Subsequent sale of subject interest
  - Subsequent sale of comparable ownership interest

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OIL AND GAS LIKE-KIND EXCHANGES

Section 1031(a) provides: "No gain or loss shall be recognized on the exchange of property held for productive use in a trade or business or for investment if such property is exchanged solely for property of like-kind which is to be held either for productive use in a trade or business or for investment." Out of this language, three specific requirements are evident: (1) exchange of properties, (2) properties are likekind and (3) properties are held for use in a trade or business or for investment.

In a deferred exchange, there are time requirements that must be met to defer taxable gain. First, there is a 45-day identification period, meaning that the taxpayer must identify the replacement property within 45 days after the disposition of his original property (the "relinquished property"). After the first requirement is met, the replacement property must be received by the taxpayer within the earlier of (1) 180 days after the date of disposition of the original property or (2) the date the taxpayer's return (including extensions) is due for the taxpayers return reflecting the year the original property was disposed. Similarly, if a taxpayer finds a property he would like to acquire and desires to exchange property he currently owns as the consideration for the new property, a "reverse exchange" can be used, and it is subject to these same time requirements.

A crucial point to remember is that in a deferred exchange, you cannot control or receive any cash paid for the relinquished property, but a qualified intermediary can hold the cash (or replacement property in the case of a reverse exchange) until you identify a replacement property. Many businesses market themselves as qualified intermediaries, and an attorney can assist you in protecting any property or cash that will be held by a qualified intermediary. It should also be noted that several individuals are disqualified from serving as a qualified intermediary, including but not limited to an employee, accountant, attorney, banker or a party related to the taxpayer including anyone owning 10 percent or more of the taxpayer. If a "disqualified person" serves as the qualified intermediary, the taxpayer will be deemed to have constructive receipt of the proceeds, meaning the transaction will be fully taxable because the taxpayer will be deemed to have control of the proceeds.

But, deductions for intangible drilling costs and depletion can be recaptured when the taxpayer relinquishes property that is subject to these deductions and receives property that is not. (See "Recapture and Taxable Boot.")

Generally, oil and gas properties qualify for the "held for" requirement, but property held only for sale will not qualify.

At the time of sale or exchange, the taxpayer may wish to retain an overriding royalty or similar interest so that the taxpayer can benefit from the continued development of the property. But, when an overriding royalty is retained in the transfer, the transaction is generally considered to be a sublease and not a sale. I.R.S. G.C.M. 22730, 1941 C.B. 214. If the transaction is treated as a lease (or sublease), the consideration received for the property will be treated as a lease bonus and will be taxed as ordinary income and

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not as a capital gain. Additionally, the consideration received will not be reduced or offset by the taxpayer's basis in the property like it would be in the case of a sale. These consequences can be disastrous but with proper planning, an interest can be held in the property and the transaction can qualify for sale or exchange treatment

As stated earlier, when related parties exchange property under Section 1031, each related party must hold the property received for at least two years.

In fact, in its Private Letter Rulings (PLR), the Internal Revenue Service (IRS) has provided guidance for using oil and gas minerals and royalties as replacement property. Here are some examples of qualifying exchanges:

- Royalty interests and commercial property. IRS finds a like-kind exchange when overriding royalty interests5 were exchanged for an apartment building, office building, and 50% interest in a condominium. (PLR 8135048)
- Royalty interest in oil and gas as real property. For tax purposes, royalty interest in oil and gas is considered real property. (Revenue Rule 55-526) Additionally, royalty interest is an interest in real property for federal tax purposes. (Revenue Rule 73-248)
- Tangible personal property. Machinery and equipment, vehicles, fixtures, and other personal property may qualify for a like-kind exchange with oil and gas property assets, such as oil and gas platforms and derricks, drilling rigs, drilling equipment, pumps, assemblies, and other machinery and equipment involved in oil and gas drilling and production operations. Such like-kind properties that are used for a business purpose may be exchanged with each other under 1031.

CONSIDERATIONS AND ISSUES IN 1031 EXCHANGES OF OIL AND GAS PROPERTY AND RULES FOR STRUCTURING AN OVERRIDING ROYALTY INTEREST

In instances where a real estate property is exchanged for an oil and gas property, the exchanging party may wish to seek an overriding royalty or similar interest so as to benefit from the continued development of the property. But, when an overriding royalty is retained in the transfer, the transaction is generally considered to be a sublease and not a sale. I.R.S. G.C.M. 22730, 1941 C.B. 214.4

An incorrectly structured exchange can pose major issues. For instance, if the IRS recognizes the exchange as a sublease and not a sale, the exchange would not qualify for tax deferment and the parties would be taxed at a regular rate.

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In order to overcome this limitation, when properties are exchanged, two separate transactions are structured. One transaction for the 1031 exchange of the property and the second (separate) transaction for the acquisition of royalty interest, which would be recognized as a sale, as opposed to a sublease.

- Partnerships. Barring a few exceptions, interests in an entity such as a partnership do not qualify as like-kind property.
- Dealers. Dealers generally do not qualify for 1031 exchange treatment due to the fact that dealers are considered to hold the property as inventory, and not for investment purposes. There are certain exceptions to this rule.

Finally, certain types of property are specifically excluded from Section 1031 treatment. Section 1031 does not apply to exchanges of:

- Inventory or stock in trade
- Stocks, bonds, or notes
- Other securities or debt
- Partnership interests
- Certificates of trust

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WHY DO WE NOT SEE THE FOLLOWING IN OIL & GAS VALUATION REPORTS WHICH ARE COMMON TO BUSINESS VALUATIONS?

Discount for the Valuation of Undivided and Non-Participating Mineral Interests

The degree to which a fractional interest should be discounted relative to an otherwise identical fee simple interest is considered. With respect to fractional discounting, the approach used by most appraisers, ten factors that affect the discount are noted, and ranges of discounts for each factor are suggested to guide appraisers in choosing an appropriate overall discount.

A fractional interest in a real estate partnership is not a fee simple interest in real estate, but is perhaps rather a security interest in a closely held business enterprise. Several factors can lessen the value of a fractional interest relative to a comparable fee simple interest.

When determining the fair market value of a fractional interest, most appraisers use the following three-step approach.

1. Determine the fair market value of the underlying asset.
2. Calculate the fractional interest's pro rata share.
3. Apply a fractional interest discount" to the pro rata share.

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Valuation Discounts for Fractional Real Estate Ownership Interests

A real estate fractional ownership interest, also called a tenancy in common interest, exists when two or more co-tenants each own a separate fractional share of undivided real property.

Although each co-tenant has an equal right to possess and enjoy the real estate, he or she cannot:

1. Exclude the other co-tenants or
2. Designate any portion of the real estate as his or her own.

By their very nature, real estate fractional ownership interests typically suffer from the following valuation influences:

1. A lack of marketability
2. A lack of ownership control

<u>Generally Accepted Valuation Approaches and Methods</u>
There are two valuation approaches and methods that valuation analysts commonly use to value a real estate fractional ownership interest:

1. The market approach and the sale transaction analysis valuation method and
2. The income approach and the partition analysis valuation method.

The Income Approach was not used as the area is not producing.

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Sale Price Discount Empirical Data
A number of empirical studies have quantified the actual price discounts associated with real estate undivided interest actual sale transactions.

The published studies generally indicate that fractional interests in properties that general significant income tend to sell for a below average price discount. The published studies also generally indicate that larger fractional interests (i.e. agreater than a 50% ownership interest) tend to sell for a larger below average price and at a discount.

Several of these published studies of real estate fractional interest empirical sale data are summarized below.

Harris-McCormick-Davis Study
The 32 sale transactions in the survey indicated an average price discount of 32.05 percent, with a standard deviation price discount of 8.29 percent.

Healy Study
The Average price discount was 23.5 percent; and, the range of price discounts w ere between 3 percent and 52 percent.

Peter Patchin Study
The average price discount associated with this study of fractional interest sales was 36.8 percent.

Peterson-Hansen-Klafter study
The number of real estate fractional interest sale transactions included in the Petrson study totaled 13, and the average price discount indicated by these transactional data was approximately 50 percent. The range of the sale price discounts was from 23.4 percent to 83.45 percent.

FMV Opinions Study
The study concluded a mean price discount of 34.8 percent and a median price discount of 32.5 percent.

Humphrey Study
Humphreys suggested that 50 percent was the threshold price discount for undivided interests.

Eckhoff Accountancy Corporation Study
In the Eckhoff Accountancy Corporation study, the average price discount was 37 percent, and the median price discount was 38 percent.

Willamette Management Associates Studies
Therefore, the total indicated price discount adjustment implied in the WMA study is on the order of 25 percent. This price discount conclusion is consistent with other WMA studies that concluded average price discounts equal to and greater than 25 percent.

In summary, the empirical evidence from all of these empirical studies supports the principle of a price discount adjustment to the pro rata fee simple market value of the real estate undivided interests.

The central tendency of the price discounts concluded in these various studies falls within a range of between 15 and 35 percent.

Court Cases
The courts have considered a variety of quantitative and qualitative considerations in the judicial determination of the value of real estate undivided ownership interest.

No single real estate fractional interest valuation method is universally accepted by the courts. In addition, the level of the valuation price adjustments allowed by the courts has varied on a case-by-case basis.

The following discussion summarizes several court cases that involve the valuation of real estate fractional interest.

1. *Estate of Forbes v. Commissioner*. The Internal Revenue Service (the "Service") applied an 18 percent fractional interest price discount.
2. *Estate of Williams v. Commissioner*. The court considered the potential $413,000 in property partition costs and real estate commissions of 10 percent that would be incurred upon the partition and/or sale of the property in its determination of the discount for lack of control.
3. *Estate of Barge v. Commissioner*. The court-determined value resulted in an effective undivided interest price discount of 26 percent from the fee simple interest market value.

1. *Shepard v. Commissioner*. The court ultimately concluded that the appropriate price discount for the undivided interest was 15 percent.
2. *Estate of Della Walker van Loben Sels v. Commissioner*, allowed a 60 percent fractional interest price discount for an undivided (tenancy in common) interest in 11 tracts of timberland.
3. *Estate of George W. Youle v. Commissioner*, allowed a 12.59 percent fractional interest discount for a 50 percent undivided tenancy in common interest in 254 acres of farmland.
4. *Estate of Wildman v. Commissioner*. This decision allowed a total 40 percent valuation adjustment for the decedent's 20 percent undivided tenant in common interest in 1,212.4 acres of farmland.
5. *Samuel J. LeFrak v. Commissioner*. The decision ultimately allowed a 30 percent combined minority interest and lack of marketability discount for the subject undivided real estate interests.
6. *Estate of Alto B*. Cervin v. *Commissioner*. This decision allowed a 20 percent fractional interest price discount for:
   a. An undivided 50 percent interest in 657.3+/- acres of farmland and
   b. An undivided 50 percent interest in a homestead.
7. *Estate of Eileen K. Brocato v. Commissioner*. The court eventually allowed a 20 percent fractional interest discount, but also had to resolve the proper amount of blockage discount to apply to the properties.
8. *Estate of Eileen K. Stevens v. Commissioner*. The court allowed a 25 percent fractional interest price discount for an undivided 50 percent interest in commercial real estate subject to a lease.
9. *Estate of John L. Baird & Estate of Sarah W. Baird v. Commissioner*. The court allowed a 60 percent fractional interest price adjustment for a 21.54 percent and a 26.15 percent fractional interests.
10. *Estate of Pearl I. Amlie v. Commissioner*. A 15 percent fractional interest price discount was applied by the court to the taxpayer's 7/12ths and 50 percent interest in two parcels of farmland.
11. *Pillsbury v. Commissioner*. The court refused to allow a price discount higher than the claimed discount of 15 percent.
12. *Van Loben Sels. V. Commissioner*. The court settled on a 60 percent discount for lack of control, but admitted to heavy emphasis on the lack of marketability of the undivided interests.

OIL GAS PRICE PROJECTIONS

Annual Energy Outlook 2017
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Month	Options	Charts	Last	Change	Prior Settle	Open	High	Low	Volume	Hi / Low Limit	Updated
APR 2017			52.37	-0.77	53.14	52.79	52.92	52.30	220,082	63.14 / 43.14	09:12:11 CT 08 Mar 2017
MAY 2017			52.91	-0.73	53.64	53.30	53.43	52.84	72,620	63.64 / 43.64	09:12:11 CT 08 Mar 2017
JUN 2017			53.31	-0.71	54.02	53.61	53.81	53.25	44,254	64.02 / 44.02	09:12:11 CT 08 Mar 2017
JUL 2017			53.64	-0.68	54.32	54.05	54.10	53.58	18,683	64.32 / 44.32	09:12:11 CT 08 Mar 2017
AUG 2017			53.87	-0.66	54.53	54.20	54.33	53.82	9,986	64.53 / 44.53	09:12:06 CT 08 Mar 2017
SEP 2017			54.03	-0.62	54.65	54.35	54.45	53.95	6,606	64.65 / 44.65	09:12:09 CT 08 Mar 2017
OCT 2017			54.18	-0.54	54.72	54.53	54.53	54.04	1,458	64.72 / 44.72	09:03:01 CT 08 Mar 2017
NOV 2017			54.21	-0.55	54.76	54.56	54.56	54.12	1,120	64.76 / 44.76	09:01:12 CT 08 Mar 2017
DEC 2017			54.16	-0.62	54.78	54.53	54.59	54.09	12,749	64.78 / 44.78	09:12:05 CT 08 Mar 2017

Legend: Options Price Chart   About This Report

http://www.cmegroup.com/trading/energy/crude-oil/light-sweet-crude.html   3/8/2017

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Glenn Hegar
Texas Comptroller of Public Accounts

2017 Property Value Study

Discount Rate Range
for Oil and Gas Properties

September 2017

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Texas Property Tax

2017 Property Value Study

Discount Rate Range for Oil and Gas Properties

Oil and Gas Property Appraisal

Discount Rate

The Oil and Gas Property Sales Analysis and Market Survey Methods

Texas Comptroller of Public Accounts • Property Tax Assistance Division — 1

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TABLE 1

Petroleum Companies' Financial Information Used for WACC Method

The Weighted Average Cost of Capital (WACC) Method

Base Discount Rate for All Oil and Gas Properties in the Property Value Study

2 — Texas Comptroller of Public Accounts • Property Tax Assistance Division

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Adjusted Discount Rate

Limited History

Type of Risk	Added Percentage Points
Limited History	
Less than one year	3
One to two years	2
Two to three years	1
More than three years	0

Single Completion Leases

Type of Risk	Added Percentage Points
Single Completion Lease	1

Offshore Leases

Type of Risk	Added Percentage Points
Offshore Lease	2

Enhanced Oil Recovery (EOR) Leases

Type of Risk	Added Percentage Points
EOR Projects	[illegible]

Other Adjustments

Type of Risk	Adjustment Trend
Short Remaining Life (< 2 years)	may increase risk
High or Increasing Water Cut	may increase risk
Gas Curtailment	may increase risk
Environmental Concerns	may increase risk
Erratic Production	may increase risk
Long History, Stable Production	may decrease risk

Reconciling Results into the Discount Rate Range

Texas Comptroller of Public Accounts • Property Tax Assistance Division — 3

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TABLE 2

Summary of Findings from Annual Sales Analysis, Market Survey and the Property Value Study

Conclusions

References

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RELINQUISHMENT ACT LANDS AND OWNERS OF THE SOIL: STATUTORY FRAMEWORK AND CASE LAW UPDATE

Source: J. Derrick Price
McGinnis, Lochridge & Kilgore, LLP

What are Relinquishment Act Lands?

- Any public fee school or asylum lands, whether surveyed or unserveyed, sold with a mineral classification or reservation between September 1, 1895, and August 21, 1931. 31 Tex. Admin. Code §10.1(a)(9).
- Estimated to total between 6.4 and 7.4 million acres
- Proceeds from Mineral Development go to Permanent School Fund
- Mineral Reservation creates two estates:
  - Surface estate – Owned by the "Owner of the Soil" or the "Surface Owner"
  - Mineral Estate – Owned by the State of Texas

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- All over the State of Texas
- High concentration in West Texas and South Texas Counties
  - El Paso
  - Hudspeth
  - Culberson
  - Jeff Davis
  - Reeves
  - Stockton
  - Presidio
  - Brewster
  - Terrell
  - Crockett
  - Valverde
  - Webb
  - Duval
  - Starr

HISTORY

Enacted in 1919, the Relinquishment Act, as interpreted by the Courts, reserves all minerals to the State in those lands sold with a mineral classification between September 1, 1895 and June 29, 1931. Under the Relinquishment Act the, "owner of the soil", also commonly known as the surface owner, acts as the agent for the State of Texas in negotiating and executing oil and gas leases on Relinquishment Act Lands (RAL). The State surrenders to the surface owner one-half (½) of any bonus, rental and royalty as compensation for acting as its agent, and in lieu of surface damages. The owner of the soil's agency power is somewhat limited, however, because the General Land Office publishes a standard RAL lease form which must be used to lease Relinquishment Act Lands. Additionally, the GLO must approve all terms including bonus consideration, royalty rates, and rental amounts, and any additional provisions for any RAL Lease. **No lease is effective until it has been approved and a certified copy of the approved lease is accepted for filing in the General Land Office.** The following information will provide some guidelines for negotiating an RAL Lease.

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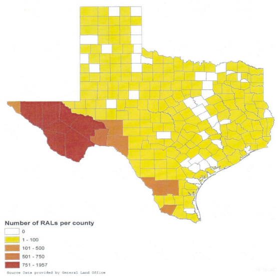
ATTACHMENT A

Number of Relinquishment Act Lands (RALs)
In Texas by County

(13,166 properties totalling 6.4 million acres)



Regulatory Definition of "Minerals"

Any naturally occurring inorganic or organic substance formed through geological processes having a definite chemical composition or a range of characteristic chemical compositions, and distinctive physical properties or molecular structure, or an aggregate thereof, that may be extracted from the earth with an expectation of profit. This includes, but is not limited to, base and precious metals, industrial minerals, such as gypsum, sulfur, talk,, etc.; coal and lignite; construction materials such as granite, limestone, rhyolite and other rock that may be quarried for dimension stone or crushed for aggregate; or sand, gravel, caliche, clay and borrow material.
31 Tex. Admin. Code §10.1(a)(5) (adopted December 4, 2009)

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Statutory Framework

- Texas Natural Resources Code Chapter 53, Subchapter C (§§53.061 – 53.081)
  - Owner of the Soil is State's Agent for leasing minerals other than oil and gas - §53.061
  - Must use lease forms prepared by General Land Office - §53.063
  - Lease must provide for at least 1/16th production royalty to the State - §53.062(c)
- For leases executed after September 1, 1987
  - Owner of the Soil receives 20% lease bonus, rentals and royalties
  - State receives 80% lease bonus, rentals and royalties §53.065 (b)
- Split is 60% to State, 40% to Owner of Soil for leases of coal, lignite, sulphur, thorium, uranium or potash executed after September 1, 1999 §53.065 (c)
- Prohibition Against Self-Dealing
  - Owner of the Soil may not lease to:
    - Himself/Herself/Itself
    - Relatives/Affiliates §53.074(a)

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- Fiduciary Duty
  - Owner of the Soil:
    - Owes the State a Fiduciary Duty and Duty of Utmost Good Faith
    - Must fully disclose facts affecting State's interest and act in best interest of the State
    - Put interests of the State before his/her own interest
    - Owes the State all common-law duties of executive rights holder §53.074(b)
- Fiduciary Duty/Prohibition against Self-Dealing
  - Breach of Owner of Soil punishable by:
    - Suit (in Travis County) to force Owner of the Soil to Perform Duties or forfeit agency rights
    - If agency rights are forfeited, State may lease to whomever it chooses as if it owned the land in fee §53.074 (c) and (d)
- Lease by Owner of the Soil
  - Owner of the Soil bay voluntarily waive agency rights and apply for lease of property from the school Land Board
  - Owner of the Soil may not receive any lase benefits (bonus, rental, royalty payments) §53.081

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CALCULATING THE BASIS OF GIFTED PROPERTY

The rules as to basis in the case of a gift do not allow for a stepped-up calculation and they depend upon whether the basis is being calculated for purposes of gain or loss. For determining gain, the basis is the same as it would have been in the hands of the donor and is called a "carryover" basis. If an individual acquired the shares of stock for $500 chooses to give them to the recipient as a gift and does not hold them until his death, the recipient takes the same $500 basis as the donor. Therefore, if the recipient sells the shares when they reach $1 million in value, the tax liability would be based on the gain of $999,500. **The choice between transferring an appreciating asset by gift and holding it until death can be crucial for purposes of the recipient's income tax liability for a later sale.**

Where an asset transferred by gift depreciates to a value below the donor's original cost, the recipient's basis is the fair market value of the asset at the time of the gift. Thus, in the above example, if the shares that had cost the donor $500 were worth $250 at the time of the gift and had depreciated in value to $150 at the time of the recipient's subsequent sale, the recipient's basis for measuring his loss would be $250, and his loss would be $100. If, however, the stock had been worth $600 at the time of the gift but had declined to $300 by the time of the recipient's subsequent sale, the basis for loss would be the donor's basis of $500 (because that figure is lower than the $600 at the value date of the gift), and the recipient's loss would be $500 less $300. - See more at:

http://corporate.findlaw.com/finance/tax-basis-of-inherited-and-gifted-property.html#sthash .welDuuyn.dpuf

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COMPUTATION OF BASIS FOR INHERITED MINERAL INTERESTS

Often time heirs receive little information on inherited mineral interests. In addition, it is common for there to be no probate or valuations done.

However, it is possible for the heirs to still obtain a valuation in order to offset the sales price.

Comparable wells are often used as a proxy for value. Cash flow for a comparable well is not defined but should have the following characteristics:

- Location
- Ownership percentage
- Initial Production (Oil, Gas, GOR, Water and Estimated Ultimate Recovery)
- Decline Rate(s) for all products
- Oil Gravity
- Gas and Natural Gas Liquids Content
- Oil, Gas, and Natural Gas Liquids Price
- Future Capital Investment
- Production Taxes
- Number of Wells, Depth, Formation
- Well type

Internal Revenue rules specify that the value for the mineral interest is determined in light of the conditions and circumstances known as of the valuation date regardless of later discoveries or improvements in methods or extractions, and/or treatment of the mineral product.

Also, basis cannot be different from what is contained in an estate return filed after July 31, 2016 pursuant to IRS Notice 2015-57.

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FAMILY LIMITED PARTNERSHIP COST DEPLETION

An individual owns a mineral interest in certain property and receives a 3M lease bonus in year 1. He forms an FLP in year 2 transferring the mineral interests and gifts - 12.25% limited partnership interests to trusts for his children. The valuation determined the total gifts were $188,000 for gift tax purposes. In year two, drilling is complete and the Partnership begins to receive oil royalties. At this time, it is expected that the Partnership will receive $2,063,096 in future oil royalties as its share of 296,800 barrels of oil to be produced over a 15-year period.

The following is an illustration of the mechanics of cost depletion on the lease bonus, depletion (cost or percentage) on the yearly payments and basis and gift mechanics.

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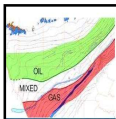

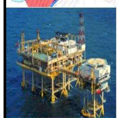

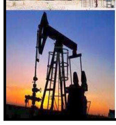

	Royalty Income	Cost Depletion	% Depletion
2013	$414,812	$672,000	$62,220
2014	$260,119	$150,000	$39,018
2015	$195,204	$125,000	$29,281
2016	$158,529	$53,000	$23,779
2017	$135,263		$20,289
2018	$125,145		$18,772
2019	$115,785		$17,368
2020	$107,124		$16,067
2021	$99,111		$14,867
2022	$91,698		$13,755
2023	$84,839		$12,726
2024	$78,493		$11,774
2025	$72,621		$10,893
2026	$67,189		$10,078
2027	$62,164		$9,325
Total	$2,068,096	$1,000,000	$310,212
Depletion Difference		($689,788)	
Difference		$689,788	
Tax Rate 34%		x .34	
Savings		**$234,528**	

Assumptions:
25% Annual Decline
Tax Rate 34%
No Depletion Deduction limitation in any year.

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Capitalized and Discounted Return Methods

The main issue in the discounted future returns method is that it requires discrete forecasts into the future, which may be unavailable, unreliable, or impractical to use. However, the consultant should be aware that the capitalized returns method is in essence a forecast as well because it assumes the benefits will grow at a stabilized rate in the future. The difference is that the presentation of the capitalized returns method appears less cumbersome. Regardless of the method used, the results should be consistent with what could reasonably be produced by some form of the discounted future returns method.

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Conditions That May Make a Discounted Return Method Inappropriate

In theory, a discounted future returns method is one of the best methods of valuing a company. It may not be accepted by some courts, however, because of its seeming reliance on forecasted future events. The values derived by these methods are only as accurate as the forecasts of future cash flows or earnings, and these future events can sometimes not be forecasted with sufficient reliability to make them usable. Understanding that no forecast is ever able to be determined with total accuracy, these methods may be problematic in either of the following situations:

a) The valuation will be used by a client (or a judicial or regulatory body) that will not accept a value based on a discounted future returns method.

b) Insufficient data exists to make a timely, reliable forecast of net cash flow or earnings for a reasonable period into the future.

When these limitations do not apply, a discounted future returns method can be useful in many circumstances. Even when one or both of the above situations do apply, the consultant may still want to use it as a reasonableness or sanity check. That is, using rough forecast estimates, the consultant may still find a discounted future returns method to be a useful and revealing tool.

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Discounted Cash Flow Method Example

INCOME METHOD

	Oil						Gas							.541348%							Value of
	Production (BBLS)	X	Oil Price	Total Oil	Severance Tax (5.10%)	Net Oil Revenue	Production (MCF)	X	Current Gas Price	Total Gas	Tax (7.50%)	Net Gas Revenue	Total Net Revenue	Cash Flow	Depletion	Income Tax (28%)	Total	Add-Back (15%)	Net Cash Flow	17% PV	Royalty Interest
2013	203,266		$79.00	$ 16,058,014	$ 818,959	$ 15,239,055	61,733		$ 3.70	$ 228,412	$ 17,131	$ 211,281	$ 15,450,336	$ 83,640	$ 12,546	$ 19,906	$ 51,188	$ 12,546	63,733.75	0.855	$ 54,473
2014	195,135		$79.00	$ 15,415,693	$ 786,200	$ 14,629,493	46,300		$ 3.70	$ 171,309	$ 12,848	$ 158,461	$ 14,787,954	$ 80,054	$ 12,008	$ 19,053	$ 48,993	$ 12,008	61,001.37	0.731	$ 44,562
2015	187,330		$79.00	$ 14,799,066	$ 754,752	$ 14,044,313	34,725		$ 3.70	$ 128,482	$ 9,636	$ 118,846	$ 14,163,159	$ 76,672	$ 11,501	$ 18,248	$ 46,923	$ 11,501	58,424.05	0.624	$ 36,478
2016	179,837		$79.00	$ 14,207,103	$ 724,562	$ 13,482,541	26,044		$ 3.70	$ 96,361	$ 7,227	$ 89,134	$ 13,571,675	$ 73,470	$ 11,020	$ 17,486	$ 44,964	$ 11,020	55,984.13	0.534	$ 29,876
2017	172,643		$79.00	$ 13,638,819	$ 695,580	$ 12,943,239	19,533		$ 3.70	$ 72,271	$ 5,420	$ 66,851	$ 13,010,090	$ 70,430	$ 10,564	$ 16,762	$ 43,103	$ 10,564	53,667.55	0.456	$ 24,478
2018	165,738		$79.00	$ 13,093,266	$ 667,757	$ 12,425,510	14,650		$ 3.70	$ 54,203	$ 4,065	$ 50,138	$ 12,475,648	$ 67,537	$ 10,131	$ 16,074	$ 41,332	$ 10,131	51,462.94	0.390	$ 20,062
2019	159,108		$79.00	$ 12,569,536	$ 641,046	$ 11,928,489	10,987		$ 3.70	$ 40,652	$ 3,049	$ 37,604	$ 11,966,093	$ 64,778	$ 9,717	$ 15,417	$ 39,644	$ 9,717	49,360.99	0.333	$ 16,447
2020	152,744		$79.00	$ 12,066,754	$ 615,404	$ 11,451,350	8,240		$ 3.70	$ 30,489	$ 2,287	$ 28,203	$ 11,479,552	$ 62,144	$ 9,322	$ 14,790	$ 38,032	$ 9,322	47,353.98	0.285	$ 13,486
2021	146,634		$79.00	$ 11,584,084	$ 590,788	$ 10,993,296	6,180		$ 3.70	$ 22,867	$ 1,715	$ 21,152	$ 11,014,448	$ 59,626	$ 8,944	$ 14,191	$ 36,491	$ 8,944	45,435.39	0.243	$ 11,059
2022	140,769		$79.00	$ 11,120,721	$ 567,157	$ 10,553,564	4,635		$ 3.70	$ 17,150	$ 1,286	$ 15,864	$ 10,569,428	$ 57,217	$ 8,583	$ 13,618	$ 35,017	$ 8,583	43,599.65	0.208	$ 9,070
2023	135,138		$79.00	$ 10,675,892	$ 544,470	$ 10,131,421	3,476		$ 3.70	$ 12,863	$ 965	$ 11,898	$ 10,143,319	$ 54,911	$ 8,237	$ 13,069	$ 33,605	$ 8,237	41,841.92	0.178	$ 7,440
2024	129,732		$79.00	$ 10,248,856	$ 522,692	$ 9,726,164	2,607		$ 3.70	$ 9,647	$ 724	$ 8,923	$ 9,735,088	$ 52,701	$ 7,905	$ 12,543	$ 32,253	$ 7,905	40,157.94	0.152	$ 6,103
2025	124,543		$79.00	$ 9,838,902	$ 501,784	$ 9,337,118	1,955		$ 3.70	$ 7,235	$ 543	$ 6,693	$ 9,343,810	$ 50,583	$ 7,587	$ 12,039	$ 30,957	$ 7,587	38,543.89	0.130	$ 5,007
2026	119,561		$79.00	$ 9,445,346	$ 481,713	$ 8,963,633	1,467		$ 3.70	$ 5,426	$ 407	$ 5,019	$ 8,968,653	$ 48,552	$ 7,283	$ 11,555	$ 29,714	$ 7,283	36,996.34	0.111	$ 4,107
2027	114,779		$79.00	$ 9,067,532	$ 462,444	$ 8,605,088	1,100		$ 3.70	$ 4,070	$ 305	$ 3,765	$ 8,608,852	$ 46,604	$ 6,991	$ 11,092	$ 28,522	$ 6,991	35,512.13	0.095	$ 3,370
2028	110,188		$79.00	$ 8,704,831	$ 443,946	$ 8,260,884	825		$ 3.70	$ 3,052	$ 229	$ 2,823	$ 8,263,708	$ 44,735	$ 6,710	$ 10,647	$ 27,378	$ 6,710	34,088.39	0.081	$ 2,765
2029	105,780		$79.00	$ 8,356,637	$ 426,189	$ 7,930,449	619		$ 3.70	$ 2,289	$ 172	$ 2,118	$ 7,932,567	$ 42,943	$ 6,441	$ 10,220	$ 26,281	$ 6,441	32,722.41	0.069	$ 2,268
2030	101,549		$79.00	$ 8,022,372	$ 409,141	$ 7,613,231	464		$ 3.70	$ 1,717	$ 129	$ 1,588	$ 7,614,819	$ 41,223	$ 6,183	$ 9,811	$ 25,228	$ 6,183	31,411.68	0.059	$ 1,861
2031	97,487		$79.00	$ 7,701,477	$ 392,775	$ 7,308,702	348		$ 3.70	$ 1,288	$ 97	$ 1,191	$ 7,309,893	$ 39,572	$ 5,936	$ 9,418	$ 24,218	$ 5,936	30,153.83	0.051	$ 1,527
2032	93,588		$79.00	$ 7,393,418	$ 377,064	$ 7,016,354	261		$ 3.70	$ 966	$ 72	$ 893	$ 7,017,247	$ 37,988	$ 5,698	$ 9,041	$ 23,248	$ 5,698	28,946.65	0.043	$ 1,253
2033	89,844		$79.00	$ 7,097,681	$ 361,982	$ 6,735,700	196		$ 3.70	$ 724	$ 54	$ 670	$ 6,736,370	$ 36,467	$ 5,470	$ 8,679	$ 22,318	$ 5,470	27,788.01	0.037	$ 1,028
2034	86,250		$79.00	$ 6,813,774	$ 347,502	$ 6,466,272	147		$ 3.70	$ 543	$ 41	$ 503	$ 6,466,774	$ 35,008	$ 5,251	$ 8,332	$ 21,425	$ 5,251	26,675.91	0.032	$ 843
2035	82,800		$79.00	$ 6,541,223	$ 333,602	$ 6,207,621	110		$ 3.70	$ 407	$ 31	$ 377	$ 6,207,998	$ 33,607	$ 5,041	$ 7,998	$ 20,567	$ 5,041	25,608.44	0.027	$ 692
2036	79,488		$79.00	$ 6,279,574	$ 320,258	$ 5,959,316	83		$ 3.70	$ 306	$ 23	$ 283	$ 5,959,599	$ 32,262	$ 4,839	$ 7,678	$ 19,744	$ 4,839	24,583.77	0.023	$ 568
TOTALS				$ 250,740,571	$ 12,787,769	$ 237,952,802				$ 912,732	$ 68,455	$ 844,277	$ 238,797,078								$ 298,823

Memo: For Illustration Purposes Only

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VALUATION ISSUES IN LITIGATION

1. Reserve Reports in Litigation

Reserve reports can form the basis for fraud or misrepresentation claims where buyers allege that the estimated reserves of oil and gas properties were significantly overstated. The qualifications of the experts are crucial to the facts. **Again what is the definition of Fair Market Value and what is or was the purpose for the valuation.**

2. Qualified Expert Opinion on Valuation

In litigation, it is almost always necessary to have an expert witness testify as to the value of oil and gas properties. As an initial matter, the party with the burden of proof must offer a witness who is a qualified expert on the subject of oil and gas valuation and whose opinions are reliable and relevant.

The following expert issues routinely arise in oil and gas litigation: (1) whether the methodology used by an expert to determine fair market value is acceptable and reliable; (21 whether a reserve report is sufficient to constitute an opinion of fair market value; (3) weighing testimony from each parties experts who offer greatly different estimate of reserves and valuation of properties; (4) whether there is evidence that an expert can correlate the "discounted cash flows" to market price during the relevant time period; (5) whether an expert's valuation follows a consistent methodology; and (6) whether an expert's fair market value opinion is supported by appropriate data available to buyers and sellers in the market place.

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VALUATION ISSUES IN LITIGATION (Cont.)

3. The Methodology Used by the Witness to Determine FMV must be Acceptable and Reliable.

It is essential that the expert witness who gives an opinion as to FMV be qualified to and actually determined the price at which these properties would change hands in an open market transaction between a buyer and a seller. **Such an expert witness typically should perform an analysis of the prices that buyers and sellers were paying for similar properties. An arbitrary application of discount rates and risk factors without regard to the market place is not calculated to yield an accurate FMV determination.** The key is what risk factors and discount rates that buyers and sellers in the market were paying for such properties on the relevant value date.

The risk factors utilized by the expert witness must be contained in the witness' report or work papers, as required by Rule 26, and in any event should be based on objective evidence rather than being entirely subjective.

Daubert, Kumho, and Frymire all make clear that an expert testifying on the subject of value must have a valid methodology and an objective basis for the opinion offered. In order to allow the witness' opinion into evidence, the court must first find that his opinion is based on valid data and a proper methodology, and is a reliable indicator of fair market value. Typically, this requires that the witness use an objectively verifiable methodology for arriving at a market value conclusion.

It is not enough for an expert to pass his hand over the worksheet and declare a particular number to be "fair market value." Expert witness testimony that is entirely subjective does not satisfy Daubert and must be excluded.

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VALUATION ISSUES IN LITIGATION (Cont.)

4. The Expert Witness Must be Qualified by Experience and Training to Render an Opinion as to Fair Market Value of Oil and Gas Assets.

It is the plaintiff's burden to demonstrate that the witness is an expert on "fair market value." **A good reservoir engineer with a great deal of experience in "modeling," may lack experience in determining the price at which the properties would change hands in an open market transaction.** In order for the opinion to be admissible, there must be some evidence that the witness can correlate his "risked discounted cash flows" to market prices during the relevant time period.

The valuation question faced by the trial court is: 1. What reserves would a purchaser perceive may be found on the debtors' properties, and what oil and gas production would a purchaser expect to achieve over time? 2. What prices and other economic factors would a potential purchaser apply to that production, in order to turn it into cash flow? 3. At what price would such properties change hands between a buyer and seller, each with relevant knowledge, and neither under a compulsion to buy or sell? A reservoir engineer may be an expert on the first (classification of reserves and engineering), but not be an expert on the last two.

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VALUATION ISSUES IN LITIGATION (Cont.)

5. The Expert's Opinion on FMV Should be Internally Consistent.

Whatever standards the proffered expert chooses to follow should be followed rigorously so as to produce an opinion that is internally consistent. This is true as to definitions of classes of reserves and use of discount rates and risk factors. An expert who fails to follow his own definitions creates an opinion that is unreliable because it is inconsistent with the methodologies stated in his own report. The opinion of an expert who fails to follow his own guidelines is inherently unreliable.

6. The FMV Opinion Must be Based Only on Data that is Available to Buyers and Sellers in the Market Place.

The definition of fair market value is that of an open market transaction between a theoretical buyer, and a theoretical seller, both without a compulsion to buy or sell, and both with knowledge of the property. **It is impossible for such an opinion to be based upon secret data that is not generally available to the public or the marketplace at large. Thus, an expert seeking to reach a FMV conclusion should not utilize, e.g., proprietary 3-D seismic to redraw the geologic maps if that data is not reasonably available to buyers and sellers in the market place.** It may be impossible for a theoretical buyer and seller to have access to this type information in an open market transaction. An opinion based upon data not generally available to potential purchasers is flawed and thus impermissibly tainted.

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VALUATION ISSUES IN LITIGATION (Cont.)

7. The Expert Must Tender a Report that Satisfies the Requirements of Rule 26(a)(2)(B), FED. R. CIV.P.

A. Rule 26(a)(2)(B) Requires a Written Report Containing the Basis for the Expert's Opinion.

Part and parcel of the pretrial process, including the court's gatekeeper role under Daubert, (discussed in detail above), is the obligation of the proponent of expert testimony to provide an expert witness report that complies with Rule 26(a)(2)(B), FED. R. Civ. P. That rule provides, in pertinent part:

B. Except as otherwise stipulated ... this disclosure [of identity of experts] **shall**, with respect to a witness who is retained or specially employed to provide expert testimony in the case be accompanied by a **written report** prepared and signed by the witness. **The report shall contain a complete statement of all opinions to be expressed and the basis and reasons therefor; the data or other information considered by the witness in forming the opinions; any exhibits to be used as a summary of or support for the opinions;**

1) The Expert Report Must Include an Explanation of the Basis for the Opinion of Value.

The basis for an expert's fair market value opinion must be contained in the written report as required by Rule 26(a)(2)(B). This is also true in bankruptcy court because Rules 26 and 37 apply through BANKR. R. 7026 and 7037, and both apply in contested matters. Rule 26(a)(2)(B) requires that the expert provide a written report, signed by him, containing his opinion and the bases for it. A failure to provide the required report means the witness may not testify.

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APPRAISAL DISTRICT VALUES FOR PROPERTY TAX

Sec. 23.01. APPRAISALS GENERALLY.
SOURCE: TEXAS PROPERTY TAX CODE

- (b) The market value of property shall be determined by the application of generally accepted appraisal methods and techniques. If the appraisal district determines the appraised value of a property using mass appraisal standards, the mass appraisal standards must comply with the Uniform Standards of Professional Appraisal Practice. The same or similar appraisal methods and techniques shall be used in appraising the same or similar kinds of property. However, each property shall be appraised based upon the individual characteristics that affect the property's market value, and all available evidence that is specific to the value of the property shall be taken into account in determining the property's market value.

Selected Excerpts Regarding Oil & Gas Appraisal Procedure

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4. Why is my property being appraised?

For ad valorem tax purposes in Texas, all property is taxable unless specifically exempted by law. Per Texas Constitution Article VIII, Section 1(a), all property must be taxed equally and uniformly. Any exemptions must be authorized [Texas Constitution Article VIII, Section 1(b)].

5. Is my mineral interest taxable if my well or lease didn't exist before January 1 of this tax year?

Texas Property Tax Code does not say that a mineral interest is taxable only if there is income being generated by the interest.

Practically speaking, however, the value of the interest may be zero (in the eyes of the appraisal district) if no income is being generated and no income could be reasonably if a well associated with that lease has not been completed before January 1.

6. Why is January 1 so important?

In Texas, all property is locally appraised "as of" January 1 of each tax year for property tax purposes, per Texas Property Tax Code, Section 23.01(a).

The value of a property at any point in time is an estimate of the price for which it would sell on January 1 under an "arm's length" agreement between a willing buyer and willing seller, with each party under no compulsion to buy or sell, the property having been exposed to the free market for a reasonable time, and with each party knowing all the uses and purposes of the property. This is known as "fair market value" and is statutorily defined in the Property Tax Code, Section 1.04(7).

15. Can I find out how much production this well or lease is making (barrels of oil, mcf of gas)?

There is no charge for access to these records. If you require production records from earlier than January 1993, or if you require historical permitting records filed for a well that are not available on-line, you will need to contact the Commission's Central Records department at (512) 463-6882. For a small charge you may obtain copies of any records maintained in the Central records department.

To obtain production information on-line, you will need the RRC Identification Number for the well, a five digit number for oil wells or a six digit number for gas wells. This identification number is required to be posted at the entrance to the property where the well is located. It is also required to be clearly stated on the payment stubs that royalty owners receive from either the operator or the pipeline gatherer/purchaser. This identification information may not be the same identification number used on any payment stub or other documentation received by a royalty interest owner.

To access production information for a specific lease, start at the home page, go to the "Data - Online Research Queries" page (see links at side or bottom of home page) and launch the "Production Data Query System (PDQ) (Statewide)" application under the Oil & Gas menu. Once the application is launched, choose the "Specific Lease Query" option. The direct link to this specific lease query is:

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Property Tax Code

Sec. 23.175. Oil or Gas Interest.
(a) [2 Versions: Effective Until January 1, 2016] If a real property interest in oil or gas in place is appraised by a method that takes into account the future income from the sale of oil or gas to be produced from the interest, the method must use the average price of the oil or gas from the interest for the preceding calendar year multiplied by a price adjustment factor as the price at which the oil or gas produced from the interest is projected to be sold in the current year of the appraisal. The average price for the preceding calendar year is calculated by dividing the sum of the monthly average prices for which oil and gas from the interest was selling during each month of the preceding calendar year by 12. If there was no production of oil or gas from the interest during any month of the preceding calendar year, the average price for which similar oil and gas from comparable interests was selling during that month is to be used. The chief appraiser shall calculate the price adjustment factor by dividing the price of imported low-sulfur light crude oil in nominal dollars or the spot price of natural gas at the Henry Hub in nominal dollars, as applicable, as projected for the current calendar year by the United States Energy Information Administration in the most recently published Early Release Overview of the Annual Energy Outlook by the price of imported low-sulfur light crude oil in nominal dollars or the spot price of natural gas at the Henry Hub in nominal dollars, as applicable, for the preceding calendar year as stated in the same report. The price for the interest used in the second through the sixth calendar year of the appraisal may not reflect an annual escalation or de-escalation rate that exceeds the average annual percentage change from 1982 to the most recent year for which the information is available in the producer price index for domestically produced petroleum or for natural gas, as applicable, as published by the Bureau of Labor Statistics of the United States Department of Labor. The price for the interest used in the sixth calendar year of the appraisal must be used in each subsequent year of the appraisal.

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17. How was my property value determined?

2. Future Oil and Gas Prices. Since tax year 1994, appraisals of oil and gas interests for ad valorem tax purposes have been required by law to use a forward-looking price scenario as laid out in Property Tax Code Section 23.175.

19. What does "fair market value" mean?

There are many definitions of the word "value" along with the many variations of this word (fair value, market value, cash value, salvage value, liquidation value, residual value, street value, full value, face value, book value, etc.). A classical definition of "fair market value" is: "...the amount a willing buyer will pay a willing seller with the property or interest exposed to market for a reasonable period, neither the buyer nor the seller under any compulsion to buy or sell, both being competent and having reasonable knowledge of the facts." Per the Texas Property Tax Code, Section 1.04(7) (see <<>>), fair market value is defined as "...the price at which a property would transfer for cash or its equivalent under prevailing market conditions if:

1. exposed for sale in the open market with a reasonable time for the seller to find a purchaser;

2. both the seller and the purchaser know of all the uses and purposes to which the property is adapted and for which it is capable of being used and of the enforceable restrictions on its use; and

3. both the seller and purchaser seek to maximize their gains and neither is in a position to take advantage of the exigencies of the other."

This is the legal definition that appraisal districts are required to use in their appraisals of property for ad valorem tax purposes in Texas. Per Texas Property Tax Code, Section 23.01(b) (see <<>>), the market value of property shall be determined by the application of generally accepted appraisal methods and techniques. If the appraisal district determines the appraised value of a property using mass appraisal standards, the mass appraisal standards must comply with the Uniform Standards of Professional Appraisal Practice (USPAP). The same or similar appraisal methods and techniques shall be used in appraising the same or similar kinds of property. However, each property shall be appraised based upon the individual characteristics that affect the property's market value, and all available evidence that is specific to the value of the property shall be taken into account in determining the property's market value.

20. What does "ad valorem" mean?

The term "ad valorem" is a Latin phrase that means "according to value."

Oil and Gas Price Forecast per Property Tax Code Section 23.175

TAX YEAR 2017

Per SB 1985 (84th regular session of the Texas legislature), Section 23.175 of the Property Tax Code was amended beginning tax year 2016 so that the forecasted oil and gas price scenario used in ad valorem tax discounted cashflow appraisals will be derived in the following manner:

1. The forecasted price for Year 1, if any, is equal to last year's average monthly price multiplied by a "Price Adjustment Factor" (PAF). This PAF is equal to the percentage increase or decrease projected for oil and gas prices for the next calendar year, compared to last year's average prices, by the United States Energy Information Administration (EIA) in their most recently published *Annual Energy Outlook*. There is a separate PAF calculated for oil versus natural gas, based on the EIA's price projection for "West Texas Intermediate Spot Average" (nominal dollars per barrel) and "Henry Hub Spot" (nominal dollars per million Btu), respectively. If the current year AEO is not published by March 1, the prices in the EIA's Short-Term Economic Outlook (STEO) as published in January of the current year will be used instead of the AEO to calculate the Price Adjustment Factor.

2. The forecasted prices for Years 2 through 6, if any, are derived by successively multiplying the calculated Year 1 price by an escalation factor which is equal to the average annual change in the Producer Price Index (PPI) for commodity data from 1982 to the most recent calendar year, as published by the United States Bureau of Labor Statistics (BLS). There is one factor calculated for oil and one factor calculated for gas. The Texas Comptroller is required to publish a manual that specifies the formula for this factor's calculation. This factor is an upper limit; the appraisal district can choose to use a smaller factor if or when appropriate.

The forecasted prices for any years in the cashflow past Year 6 are equal to the price used in Year 6.

	Oil	Gas	
a. Most Recent Previous Year's Price (EIA)[1]:	$42.78	$2.50	
b. Projected Next Year's Price (EIA):	$49.99	$3.06	
c. Calculated PAF for Year 1 Price:	1.16854	1.22400	= (b / a)
=	16.854% escalation	22.400% escalation	
d. PPI Index in 1982 (BLS)[2]:	100.0	100.0	
e. PPI Index for Most Recent Previous Year (BLS):	111.7	96.6	
f. Years Elapsed from 1982:	34	34	
g. Calculated Factor for Years 2-6 Prices:	1.00326	0.99898	= (e / d)^(1/f)
=	0.326% escalation	0.102% de-escalation	

[1] EIA price data is for West Texas Intermediate (formerly called Imported Low-Sulfur Light Crude Oil by EIA) and Henry Hub Spot Price as published in EIA's "Reference Case" Table 12 (Petroleum Product Prices) and Table 13 (Natural Gas Supply, Disposition, and Prices), in nominal dollars per barrel and million btu, respectively. Alternatively, in years where the AEO is not used, these prices are from the EIA's January STEO publication, Table 2. The prices shown in rows a and b above have been rounded to two decimal places before calculation of the PAF in row c.

[2] BLS PPI data is for Domestic Crude Petroleum (commodity code 0561) and Natural Gas (commodity code 0531), non-seasonally adjusted, under the Fuels and Related Products and Power group (group 5). The yearly average PPI figures shown in rows d and e above have been rounded to one decimal place before the calculation in row g.

Tax Reform Provisions Application to Oil & Gas

The plan passed expands the kind of income eligible for reduced tax rates for pass-through entities, like partnerships and limited-liability companies. Oil and gas partnerships may be eligible under the bill.

Instead of paying a top income-tax rate of nearly 40 percent, they would face an effective rate of about 33 percent because of a 20 percent deduction allowed for pass-through income.

Reduction in Corporate Tax Rate

Senate eliminates the graduated corporate rate structure and instead taxes corporate taxable income at 21 percent. It also eliminates the special tax rate for personal service corporations and repeals the maximum corporate tax rate on net capital gain.

Enhanced expensing Through Bonus Depreciation

The Bill extends and modifies the additional first-year (i.e., "bonus") depreciation deduction through 2022 (through 2023 for longer production period property). Under the Bill, the 50-percent allowance is increased to 100 percent for property placed in service after September 27, 2017,, and before January 1, 2023 (January 1, 2024, for longer production period property and certain aircraft), as well as for specified plants planted or grafted after September 27, 2017, and before January 1, 2023.

Enhanced Expensing Through Section 179 Expense Deductions

The Bill increases the maximum amount a taxpayer may expense under Code Sec. 179 to $1,000,000, and increases the phase-out threshold amount to $2,500,000. Thus, the proposal provides that the maximum amount a taxpayer may expense, for taxable years beginning after 2017, is $1,000,000 of the cost of qualifying property placed in service for the taxable year. The $1,000,000 amount is reduced (but not below zero) by the amount by which the cost of qualifying property placed in service during the taxable year exceeds $2,500,000.

Changes to Interest Deduction Rules

Under the Bill, in the case of any taxpayer for any taxable year, the deduction for business interest is limited to the sum of business interest income plus 30 percent of the adjusted taxable income of the taxpayer for the taxable year. This does not apply to pipeline companies but does apply to oil & gas.

Deductions

Repeal of Domestic Activities Production Deduction. Under the Senate Bill, the deduction in Code Sec. 199 for domestic production activities is repealed for taxpayers other than C corporations, effective for tax years beginning after 2017.

Partnership Audit Rules

Bye bye TEFRA! The Bipartisan Budget Act of 2015 §1101, Pub. L. No. 114-74, signed by the President on 11/2/15, made sweeping changes to the partnership audit rules. The TEFRA rules (in §§ 6221-6231) and Electing Large Partnership rules (in §§ 6240-6242, 6245-6248, 6251-6252, and 6255) have been repealed and replaced in new §§ 6221-6223, 6225-6227, 6231-6235 and 6241, with an entity-level audit process that allows the IRS to assess and collect the taxes against the partnership unless the partnership properly elects out. The new rules will simplify the current complex procedures on determining who is authorized to settle on behalf of the partnership and also avoid the IRS's need to send various notices to all of the partners. Under the new provisions the IRS may reduce the potential tax rate assessed against the partnership to take into account factors such as tax-exempt partners and potential favorable capital gains tax rates. The new rules should significantly simplify partnership audits. As a result, the audit rate of partnerships might increase. Although partnerships with 100 or fewer partners can elect out of the new rules, §6221(b), such election is not available if there is another partnership as a partner. Implementation of the new rules is deferred; the new rules apply to partnership taxable years beginning after 12/31/17. Partnership agreements should be amended to take into account these changes.

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Who can be the Partnership Representative?

- In order to be the partnership representative, the person must have (1) a substantial presence in the United States; and (2) the capacity to act.
  - Unlike TEFRA, the partnership representative does not have to be a partner.
- A person has a substantial presence in the United States if the person:
  - can meet in person with the IRS at a reasonable time and place;
  - has a U.S. street address and telephone number; and
  - has a U.S. taxpayer identification number.
- If the partnership representative is an entity, the partnership must identify an individual that can act on the entity's behalf that satisfies the eligibility requirements.
- **Note**: Actions taken by an ineligible partnership representative are valid and designation remains in effect until terminated (by resignation, revocation or IRS determination).

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From now on, unless your partnership is eligible to elect out, and does elect out, the IRS will only deal with the PR, and the partners have no rights to separately appeal a tax assessment. The PR also has the power to take other binding actions with the IRS that you cannot appeal. These include:

— Waiving the Statute of Limitations or other defenses;
— Communicating with the IRS and agreeing to settle the total tax liability of all the partners;
— Once the total tax assessment is agreed, the PR is able to elect to either:
 – allocate that total amount among the partners, so the IRS can collect a specific amount from each partner or
 – pay the tax on each partner's behalf at the partnership level.

Moreover, the new rules eliminate the concept of notice partners who are entitled to hear directly from the IRS. So, an audit could commence and run its course, and unless the PR keeps the partners informed, they might never know about it until they get a bill that is no longer appealable.

Some partnerships will be able to elect out of this new centralized audit regime. To be eligible, the partnership must have 100 or fewer partners, all of whom are individuals or C corporations. The new rules are mandatory for everyone else. And the election must be made by the entity. The partners themselves have no ability to elect out. If your partnership can elect out, you and your partners should seriously consider doing so. If you can't—or if you're unsure—here are some important questions the investors and the managing partners should answer in the form of amendments to the partnership agreement.

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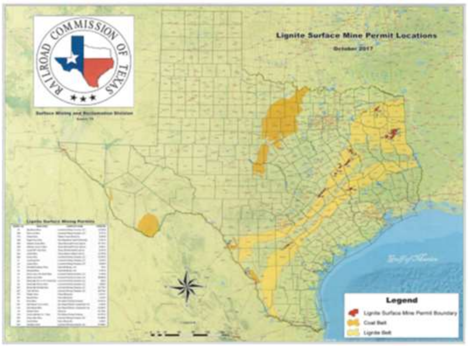
And Yes Virginia Has Coal



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Texas is undeniably a principal in the oil and gas industry. The Lone Star State is also surging ahead in green electricity, boasting one-fifth of the ~68 GW of wind power currently installed in the United States. But, perhaps less known is that Texas:

1. is the nation's sixth largest producer of coal.
2. is the nation's leading producer of lignite coal.
3. produces this lignite coal exclusively in strip mines.

The American Society for Testing and Materials groups different types of coal into four ranks – anthracite, bituminous, subbituminous, and lignite. Anthracite coal has the highest amount of fixed carbon and the lowest amount of moisture of the four groups. In turn, it is the easiest to burn and has the most energy per pound of coal. At the other end of the spectrum is lignite – or "brown coal" – the type of coal currently being produced in mines across Texas.

According to the University of Texas Energy Institute's Assistant Director Dr. Fred Beach, lignite coal is essentially "brown dirt" and frequently referred to as "oil mud." Because of its low energy-density and high moisture content, lignite coal is the least efficient type of coal to burn. However, because of its proximity to many of Texas's coal-fired power plants, it is frequently the most economic option.

Coal-fired power plants exist in Texas where "you're literally digging [lignite coal] out of the ground, putting it on a conveyor belt, and it's going right into the power plant" says Beach. These mine-to-mouth power plants exist at many locations in Texas, including next door to the state's capital city.

All told, two-fifths of coal consumption is Texas is met using locally-mined lignite coal. The rest of its demand is met using subbituminous coal brought in from Wyoming.

Texas lignite coal is produced exclusively via surface strip mining (also called open-pit mining). While Texas historically been produced its lignite using underground coal mining, producers began using strip mining techniques in the 1920s. According to the Texas Railroad Commission, by 1951, this method was the only one being used to produce lignite coal.

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COAL INCENTIVES

Federal tax incentives pertaining to coal include:

• **Percentage depletion for hard mineral fossil fuels** - Pursuant to Sections 611 through 613A and 291 of the Internal Revenue Code, percentage depletion is available for coal and lignite at a rate of 10 percent of gross income from the property. The deduction is limited to 50 percent of taxable income from the property. For corporations, the percentage depletion for coal and lignite is reduced by an amount equal to 20 percent of the percentage depletion that exceeds the adjusted basis of the property.

• **Expensing of exploration and development costs for hard mineral fuels** - Pursuant to Sections 617(a) and 291 of the Internal Revenue Code, a mining company may elect to deduct 70 percent of the cost of domestic exploration and development. The remaining 30 percent of expenses must be capitalized and amortized over a 5-year period. Pursuant to Section 59(e) of the Internal Revenue Code, a taxpayer also may elect to capitalize mine exploration and development expenses and amortize those expenses over a 10-year period.

• **Capital gains treatment of coal royalties** - Pursuant to Section 631(c) of the Internal Revenue Code, a taxpayer that owned minerals in place for at least 1 year before the minerals were mined may treat the royalties from the mined coal as long-term capital gains rather than ordinary income.

• **Advanced coal project credits** - Pursuant to Section 48A of the Internal Revenue Code, tax credits equal to 30 percent of qualified investments are allocated to projects that use integrated gasification combined cycle or other advanced coal-based electricity generation technologies to capture and sequester 65 percent of carbon dioxide emissions.

• **Gasification credit** - Pursuant to Section 48B of the Internal Revenue Code, tax credits equal to 30 percent of qualified investments are allocated to gasification projects that capture and sequester at least 74 percent of carbon dioxide emissions.

• **Carbon dioxide sequestration credit** - Pursuant to Section 45Q of the Internal Revenue Code, a credit is available for the sequestration of carbon dioxide captured from industrial sources. The credit is equal to $10 per metric ton, adjusted for inflation, for carbon dioxide used as a tertiary injectant in a qualified enhanced oil or natural gas recovery project. The credit is equal to $20 per metric ton, adjusted for inflation, for carbon dioxide permanently sequestered without first being used as a tertiary injectant. The credit is disallowed at the end of the calendar year in which 75 million metric tons of qualified carbon dioxide is certified as having been injected or sequestered.

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SUMMARY

In summary, the fair market value of an oil and gas interest is a function of its anticipated capacity to produce cash flow. For producing properties too small to justify a detailed engineering study and for non-producing properties, detailed information must be developed in order to select an appropriate multiple of production or bonus income to estimate fair market value. The appropriate multiple will, in almost every case, be significantly lower than a multiple of earnings appropriate to securities or surface interests in real estate.

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