Oil and Gas Audits

If you are in the Oil and Gas business, the following is a synopsis of what to expect during an audit of your business by the Internal Revenue Service.

Property Overview

IRS examiners will focus on and you should become familiar with the concepts of mineral interests and "property". The "property" concept serves as the basis for defining the tax entity for purposes of depletion, abandonment losses, recapture rules, etc. and may vary from traditional notions of property. I.R.C. §614 defines property as "each separate interest owned by the taxpayer in each mineral deposit in each separate tract or parcel of land." Each different type of interest is treated as a separate property, so if a taxpayer has a royalty and working interest in the same tract of land, it is treated as two separate tax properties. Tracts with a contiguous (or common side) are treated as one property for tax purposes.[1]

Taxpayers have attempted to manipulate the §614 definition in order to take larger or premature deductions for depletion and abandonment or to manipulate recapture by accounting for income and expenses on a well-by-well basis in the accounting records or by segregating income and expenses by prospect. The IRS is aware that many taxpayers will not convert internal records to appropriately conform to the §614 definition of property. For this reason, you should be aware that examiners will look for this problem when sorting through accounting records.

Examiners may ask you what definition you use for property in computing depletion or other related expenses. Examiners may also request copies of your depletion schedules for the current, prior, and subsequent years. If you have the well account numbers on the schedules, the examiner may compare the groupings of these account numbers between years to see if you change the property definition each year to obtain the best deduction.

If an examiner wishes to test some properties, a sample selection will be made to determine compliance with I.R.C. §614. The examiner will then request a lease file on each property sampled and review the lease file to determine the interests owned on each lease and the tract of the property. The examiner may then compare the property tract description with a map to determine if the property has been appropriately classified for accounting purposes under I.R.C. §614. Other examination procedures may consist of inquiries, such as asking you if there is new unitization or pooling agreements for the

[1] Tracts sharing only a corner are considered separate properties.

current year.

Oil and Gas Accounting Methods – Book versus Tax

The examiner will be familiar with the differences between the successful efforts method, full cost method, and tax method of accounting. Although you have the option of using an accrual method or cash method of accounting in conjunction with either successful efforts or full cost for financial reporting purposes, IRS examiners are notified of necessary adjustments to appropriately convert accounting records from one of the two book methods to the tax method. In the cash method of accounting, items are recorded when cash comes in or goes out. With the accrual method, expenses are recorded when incurred (regardless of when they are paid) and revenues are recorded when earned (regardless of when cash is received). Differences between the two oil and gas book methods of accounting and the tax method along with common tax adjustments are explored in further detail below.

Successful Efforts Overview

When recording items under the successful efforts method, the cost center is a lease, field, or reservoir.

Acquisition or Leasehold Costs

In successful efforts, acquisition costs for unproven property are capitalized until either proven reserves are found or the property is impaired (or abandoned). When proven reserves are discovered, the property is reclassified to proven property. Any further associated production costs for the proven property are expensed for both book and tax purposes. For book purposes, a partial impairment is allowed. The tax method treats acquisition costs in the same manner, except that property cannot be partially impaired. The property must be abandoned before a write off is allowed. The result is a common M-1 adjustment to recapitalize any portions of partially abandoned property.

Exploration Costs: G&G and Drilling Expenses

For financial reporting purposes, exploration costs are recorded based on the type of cost incurred: non-drilling or drilling. Non-drilling costs are geological and geophysical (G&G) costs, costs of retaining undeveloped properties, and dry hole and bottom hole contributions. These costs are expensed. However, for tax purposes, non-drilling costs are capitalized to the appropriate property and amortized over the appropriate timeframe or expensed in the year it is determined no provable reserves exist. This creates a book to tax depreciation base difference resulting in an M-1 adjustment for the capitalized property and depreciation expense.

Drilling costs are treated differently depending on whether the well is exploratory or developmental in nature. An exploratory well is a well drilled in an unproven area. A developmental well is a well drilled to produce from a proven reserve. If a well is exploratory in nature, dry hole drilling costs are expensed. The drilling costs of a successful exploratory well are capitalized to the well. All drilling costs for developmental wells are capitalized to the related property even if a dry hole is drilled.

For tax purposes, there is no distinction, for drilling cost purposes, between exploratory and developmental wells. Everything is considered a development cost under the tax method. Intangible drilling costs (IDC) are those costs with no salvage value. These include labor expenses, fuel, supplies, etc. For either type of well IDC are capitalized. The taxpayer can elect to have domestic IDC expensed, but foreign IDC will still be capitalized. The election must be made in the first year these costs are incurred, and the election is sometimes binding on the taxpayer for subsequent years depending on the type of well. Typically the election is made to expense these costs. If a taxpayer capitalizes IDC, then dry hole costs must be capitalized unless an election is made to expense dry hole costs.

Tangible drilling costs are capitalized under the tax method regardless of the type of well drilled. The depreciation on this capitalized property is taken as a deduction for income tax purposes. Tax depreciation methods are usually more accelerated than book depreciation. Also, the book depreciation is calculated on the developmental dry holes and IDC since these items are capitalized. The result is another book to tax adjustment.

Since there are several book versus tax differences between capitalization and expense for exploration costs under this method, common M-1 adjustments arise from depreciation and depletion expense because of the difference in the capitalized base.

Full Cost Overview

Under the full cost method, all costs incurred, except for production costs, are capitalized to the relevant cost center. Since virtually all costs are capitalized, the tax differences resulting in M-1 adjustments arise from costs that are expensed under the tax method. Unsuccessful G&G costs are among the notable tax method difference in comparison to the full cost method. These costs are expensed for the tax method and cause an M-1 adjustment.

All dry hole costs are capitalized under the full cost method of accounting. In most cases, a taxpayer elects to expense these costs for an immediate deduction. Thus, an M-1 adjustment is required.

Along with traditional well costs, an M-1 adjustment results when property is fully abandoned because although deductible for tax purposes, these property values remain capitalized in the cost center under the full cost method of accounting.

Full cost does allow for expensing General and Administrative (G&A) costs not associated with acquisition, exploration, and development. However, overhead (OH) costs that can be allocated to acquisition, exploration, and development are capitalized under full cost. The tax method treats these costs the same way.

As noted above with successful efforts, depletion usually requires an M-1 adjustment because of the differing capitalization rules.

Specific Audit Techniques

In addition to audit techniques geared at identifying whether you are using a different definition of property from I.R.C. §614, the examiner will use other procedures designed to test specific account items. When an examiner receives a tax return for examination, it is analyzed for M-1 book to tax return differences related to these accounts. Before diving into specific accounts and items to determine these differences, examiners will ascertain which accounting method you are using. The examiner will ask you which method you are using and request the book to tax adjusting journal entries. If you are unable to provide this information, the examiner will look at specific costs you expense versus capitalize to deduce what method of accounting for oil and gas you use for book and financial reporting purposes. The examiner will then look for common account adjustments specific to each of the two acceptable book accounting methods based on some of the common differences between the tax method and the two book methods noted above. The examiner will often focus on common oil and gas accounts with significant account activity using the procedures noted below to make audit adjustments for tax purposes.

Gross Income Sources and Associated Audit Techniques

Oil and gas companies and individual royalty interest owners typically receive income from multiple sources. The examiner will be familiar with specific procedures performed on various income sources. For tax purposes, the risk related to revenue is underreporting.

Thus, the procedures are compiled to address completion audit risks with respect to the various oil and gas income sources. Although these items are often deductible by the party making the payments, the procedures below are addressed from the lessor or receiving party perspective.

Oil and Gas Sales

Gross revenue from oil sales is determined by multiplying the barrels of oil delivered by the price per barrel of the particular grade of oil and gross revenue from gas sales is determined by multiply the cubic feet sold, according to the gas settlement statement, by the contract price. The examiner will independently verify the quantities of product leaving the properties by examining oil run tickets prepared and meter reads from gas pipelines. These quantities are multiplied by the price to determine if the revenue recorded is appropriate. The examiner will perform additional procedures to ensure the amount recorded is appropriate based on the percentage and type of interest held.

The purchaser of oil and gas uses a division order as the basis for paying revenues to the economic interest owners after paying the applicable severance taxes. The division order typically directs the purchaser to pay royalty interest owners directly and remit the receipts payable to the working interest holders to the operator. Purchasers of gas usually will remit 100 percent of the proceeds, less severance taxes, to the operator. For testing purposes, examiners will obtain a copy of the division order and lease to compare the ownership percentages designated to the receiving taxpayer with the percentage interest used to calculate the amount actually paid on the remittance slip. This ensures that gross revenue sales are appropriately distributed and recorded as revenue by the receiving party.

Working Interest Owners

Since working interest owners receive the largest share of the oil and gas sales payments, the examiner will compare current and prior year oil and gas depletion schedules for significant changes in properties between years. The examiner is specifically looking for properties that operate at a loss with no drilling or development, report income out of line with expenses claimed, drop off the depletion schedule when no significant sales income is noted, or incur large amounts of IDC just before property is transferred. These schedules are also compared with division orders to determine how much the working interest owner should be receiving and reporting in a tax year. Lease agreements and amendments may be requested to verify that division orders are complete and accurate.

Lease Bonus

A bonus is paid for the execution of an oil and gas lease and is regarded as ordinary income to the lessor. If the rights to the bonus payments are freely transferable, the total amount of the bonus is included in income at the time the lease is executed, even if the payments are made in installments. The examiner will look at lease agreements to determine if certain annual payments will be made for a fixed number of years. Checks received for these payments may be reconciled with the amount per the lease agreement. This helps the examiner determine if income is underreported during a taxable year.

Delay Rentals

Delay rentals are amounts paid to the lessor for the privilege of deferring the commencement of a well on the lease and are reported as ordinary income. They are paid as a situation giving rise to no production occurs. The examiner will inspect lease agreements with payments received to identify any underreported taxable income.

Royalty Income

A royalty interest entitles the holder to a specific percentage of production income free from development and operating expenses. This is reportable as ordinary income. To ensure no underreported taxable income exists, the examiner will inspect the division order agreements or lease agreements and compare these items with check stubs and remittance slips to make sure the amount received is the same as the amount of revenue recorded.

Advance Royalties

Advance royalties result from lease provisions that require the operating interest owner to pay a specified royalty regardless of whether any oil or gas is extracted during the period. These items are taxable as ordinary income to the lessor and are tested by the examiner in a manner similar to that of royalty income.

Shut In Royalties

These royalties are payable to royalty owners when a well capable of producing in commercial quantities is shut in. These are reportable as income by the receiving party and are also tested by the examiner in a manner similar to royalty income.

Production Payments

A production payment is a right to oil, gas, or other minerals in place that entitles its owner to a specified fraction of production until a specified amount of money or minerals has been received. These payments made are treated as ordinary income to the holder of the right.

Damages

The land surrounding a well can be damaged when a well is drilled. The surface right owner is usually entitled to a reimbursement for these damages. The surface user agreement will be examined to determine the amount to be paid and what costs are covered. Costs reimbursed for profits and losses should be reported as ordinary income. Other damage receipts are taxable as a capital gain in certain situations. The amounts received are compared with the agreement to ensure that items are appropriately reported for income tax purposes.

Shooting Rights

To avoid expensive leasehold costs, an operator may enter an agreement to pay a smaller amount under a contract which gives the operator the right to enter onto the property and conduct exploration activities, but grants no drilling or production rights. These amounts received are reportable as ordinary income by the landowner. The contract will be examined and compared with amounts received to confirm that no revenue is underreported.

Capitalized Property

For tax purposes, under I.R.C. §263A, most costs associated with production of oil and gas are capitalized. Some predevelopment costs may be expensed if no proven reserves are located. However, most costs are capitalized to the appropriate cost center and recaptured as a deduction through depletion or depreciation expense.

Producing Property

Producing property could include G & G data, acquiring and developing the leasehold mineral interest, constructing tangible and surface well equipment, and carrying oil and gas inventory (barrels of oil and MCF of gas). Undeveloped leases are not included.

Predevelopment Expenses

Direct costs of labor and material that are directly related to a property are capitalized for tax purposes. These items include direct labor and fringe benefits. Indirect costs are also allocated to the appropriate property and capitalized. The allocation should be based on matching activities to the benefit derived from the indirect costs incurred. For tax purposes, the allocation should be consistent from year to year.

Interest Expense

Interest traced to a property should be capitalized to that specific property. Additionally, interest on debt allocable to leasehold costs is capitalized during the production.

The related Treasury Regulations outline some of the specific costs included in the capitalized property categories above. Aside from determining if the appropriate production period has been utilized by the taxpayer, the examiner will review the taxpayer's account entries to determine if costs have been appropriately capitalized. If errors are noted, the examiner will make adjusting journal entries to convert the financial records from the book method to the tax method of accounting.

Leasehold Costs

Leasehold costs are the costs associated with acquiring or retaining a lease. These costs include commissions or finders' fees, abstracting costs, attorney's fees for title opinions, drafting deeds, and instruments of conveyance. The landman's salary/contract labor should be a part of the capitalized leasehold cost if it can be matched with the acquisition of a particular lease. If a lease expires, a taxpayer is allowed to write off the capitalized cost of the lease, even if a new lease is later obtained on the same property. A loss is not allowed if a new lease is obtained covering the property before the old lease expires. In that case, the costs of the old and new lease are capitalized to the same property.

The examiner is encouraged by their managers to scan nonproducing leases recorded on the balance sheet to determine if the costs associated with these leases have been incorrectly expensed as production costs.

Geological and Geophysical (G&G) Costs

Geological methods consist of the search of a surface for indications of hydrocarbons, geological mapping, topographical mapping, aerial photography, and radiation surveying.

These exploration costs must be capitalized for tax purposes. Problems with capitalization of these expenses are often noted by operators.

Most operators will capitalize the costs that were paid to engineers and geologists outside the company, but they will not capitalize a portion of the salaries and overhead allocable to in-house personnel who perform the same types of services. The examiner will perform reviews of the account entries and ask for corroborating information to determine what portions of in house costs should be capitalized.

The amount of G & G costs to be capitalized by a taxpayer depends upon the taxpayer's operations. Taxpayers that only purchase producing properties simply capitalize the purchase price to leasehold costs. All subsequent costs related to product are expensed for tax purposes.

Additionally, taxpayers performing significant exploration activities may attempt to claim a larger interest area so costs can be written off quickly as abandonment expense for tax purposes.

To address these audit risks, the examiner will often utilize the help of an engineer. However, other procedures are performed by the examiner without utilizing outside help. For example, the examiner will assess whether the taxpayer is in the business of exploration or development. This determines whether a taxpayer is frequently purchasing producing wells or obtaining unproven leases. If the taxpayer frequently purchases already producing property, the examiner will verify that the time spent analyzing the potential production payouts are appropriately included as additional G&G expenses capitalized to the property. The examiner will likely request a list of properties acquired during the year and determine the people involved with analyzing purchase decisions or other overhead items as well as G&G direct and indirect costs are appropriately capitalized. A comparison will be conducted with the lease list to the costs incurred during the year to see where all costs associated with the leases were recorded. If items were expensed, reclassifying journal entries will be posted to include the items as a part of the balance sheet leasehold costs for tax purposes.

For taxpayers in the exploration side that purchase unproductive property, there may still be areas of interest held during a year. The examiner will often look at leases acquired during the year and costs recorded for surveys, overhead, and other engineering or geological costs. These items should be capitalized for tax purposes and will be reclassified by the examiner if the items have been expensed.

Abandonment Cost

The examiner will look at abandonment costs to ensure deductions are appropriate. If the well was plugged and the report was filed with the proper state agency, the report would support an allowance of a deduction for the abandonment loss. However, the examiner will verify that the well was not reentered. In addition, the examiner will determined that the "entire property" under the definition of property was abandoned because deductions for impairment are not allowed under the tax method.

For non-producing properties without executed leases, the examiner may perform one or more of the following procedures to verify abandonment losses:

1. Obtain a breakdown of the abandonment expense by amount and name.
2. Request a breakdown of the cost incurred on the properties.
3. Determine what the project area was, and what the areas of interest were.
    a. Obtain a name and description from you for the project area and the areas of interest.
    b. Have you show the boundaries of the project area and the areas of interest on a map or plat.
4. Determine if additional costs were expended on an area of interest after it was identified as such. (If no additional costs were incurred, the area was probably not a true area of interest. If the amount is material, an engineer may be consulted.)
5. If no reserves were determined in the whole project area, the costs associated with the project may be abandoned.
    a. Determine whether the amount expended applies only to the project area in question.
    b. Test the allocation of the costs to the area of interest.
        1) Costs that are not direct costs of an area of interest are allocated equally between areas of interest. Areas of disinterest in the project area should receive no allocation.
        2) Direct costs of an area of interest should be directly assigned to that area of interest.
6. If reserves were determined in a particular area of interest, but no lease was acquired, determine that no lease was acquired by the following:
    a. Question you as to whether any leases were acquired in or adjacent to the area of interest.
    b. Scan subsequent year acquisitions to determine whether leases in this area of interest were acquired in a subsequent year.

7. Determine that an "identifiable event" has occurred allowing the write off of the costs incurred. An "identifiable event" occurs when one of the following criteria exists.
    a. A lease sale that includes the area of interest involved and you are unsuccessful in obtaining a lease;
    b. An indication that the area of interest will not be included in a lease sale;
    c. An event that establishes that the area of interest is worthless; or
    d. There has been an elapsed time of 5 years for onshore properties, or 10 years for offshore or Government properties.
8. Verify the amount of the abandonment loss for the area of interest by testing the allocation of costs. Inspect records showing costs charged to the area of interest.
    a. Costs that are not direct costs of an area of interest are allocated equally among the areas of interest. Areas of disinterest in the project area should receive no allocation.
    b. Direct costs of an area of interest should be directly assigned to that area of interest.

For non-producing properties with executed leases, the examiner may perform the procedures listed below on one or more of your properties to verify abandonment losses:

1. Obtain a list of the properties abandoned by you.
2. Request the lease file on the abandoned properties.
    a. Determine from the lease agreement if the primary term of the lease expired during the year under audit.
        1) If the lease has expired, you have sustained a loss.
        2) If the lease expired prior to the audit year, the loss would not be allowable in the year of examination. However, if the prior year's statute of limitations has not expired, the loss would be allowable in the year of expiration.
    b. If the primary term is still in effect, determine if you ceased to pay delay rentals on the lease in the year under audit.
        1) Inspect the lease agreement, and determine when payments should have been made. Determine if payment was not made.
        2) Inspect the delay rental record for each non-producing lease. If a payment was not made on the next due date, there may be a notation.
        3) Inspect the lease file for any correspondence or notes about allowing the lease to lapse.
            a) If the delay rental date lapsed during the year under audit, you have sustained a loss.

b) If the delay rental lapsed prior to the audit year, the loss would not be allowed.

c) If the delay rental was paid and in force during the audit year, a loss would not be allowed unless a quit claim deed was executed or the primary lease term lapsed without production.

c. Determine if a quit-claim deed was executed by you.

1) Inspect the lease file and ask for the quit claim deed. Ensure the date it was executed is in the taxable year under examination.

2) If a quit claim deed was not executed in the audit year, you will not be allowed an abandonment loss unless the primary term has lapsed without production or a delay rental was not paid in the audit year.

Lease Operating Expense

In the oil and gas industry, operating expenses are commonly referred to as lease operating expense (LOE). LOE includes the cost of operating and maintaining producing leases. It also includes the cost of labor for operating and maintaining the equipment on the lease, repairs and supplies, utilities, automobile and truck expenses, taxes, insurance, and overhead expenses such as bookkeeping, billing costs, and correspondence. These expenses are deductible in accordance with your method of accounting, either cash or accrual basis. The examiner will look through LOE to make sure that items are properly deducted for income tax purposes.

Bad Debts and Joint Interest Billing (JIB)

Operators will incur the costs of operating a well and bill out other working interest owners for the percentage share of the costs incurred. This process is referred to as joint interest billing (JIB). Sometimes a working interest owner will refuse to pay its share of the drilling or operating costs of a well or property. If the property is a producing property and the operator is receiving the funds from oil and gas sales, the operator can offset these funds against the share of the working interest owner that is not being paid on the property. If a property is dry, or the purchaser pays all working interest owners directly, the operator may sue the nonworking interest owner for breach of contract for nonpayment of its JIB.

The examiner may request a detail of the items making up bad debt. When making the request for the list, the examiner may also ask for an explanation of how each item in bad debt came about and was calculated. These calculations will then be reviewed for accuracy. Most operating agreements will give the operator specific remedies for nonpayment, and the examiner will look to see if you were remedied for nonpayment in accordance with the agreement. If the property was non-producing, the examiner will determine whether you are dealing with the same person on other new ventures and the reasons for continuing to work with someone when payments have not been received on prior projects. This procedure helps the examiner determine if you are claiming “fictitious” bad debt expenses.

The examiner will also likely request any settlement contracts for the bad debt examined. These contracts provide the terms of the settlement and are compared with the bad debt expense recorded to determine if the bad debt was appropriately calculated. If suspended proceeds were ultimately received on the account, the examiner will compare these proceeds with the total accounts receivable (A/R) ultimately recorded as bad debt to make sure that you appropriately reduced A/R prior to writing off the remaining uncollectable A/R balance as bad debt expense.

Property received as part of a settlement should reduce the amount owed to you by the fair market value of the property before arriving at a bad debt expense. The examiner will look at the settlement agreement to see if any property was received in the process. The examiner will then determine if the correct fair market value of the property was used to reduce total A/R prior to arriving at the bad debt expense deduction. To determine if you accounted for the correct fair market value, the examiner will perform the following procedures:

1. Obtain copies of the operator's reserve calculations for the property in question.
2. Determine the fair market value of the property received by using the discounted cash flow value of the property.
3. If the working interest revenue and expense ownership interest are different, additional steps may be performed. If the fair market value is material, the examiner will consult an IRS Engineer to determine the appropriate FMV for bad debt expense calculations.
4. Compare the predicted value calculated to the fair market value which you used in determining bad debt expense.

Intangible Drilling Cost (IDC)

IDC are expenditures for drilling wells or developing wells that are intangible. The term intangible denotes costs that have no salvage value, or cannot be depreciated. Therefore, IDC are all costs which are the intangible costs of drilling up to and including the cost of installing the "Christmas tree." The term "Christmas tree" refers to the pipes, valves, and fittings that are used to regulate the flow of oil and gas from the wellhead. IDC does not include the physical components of the "Christmas tree" because these costs are capitalized and depreciated due to the salvage value. However, administrative drilling costs, road construction to the drill site, transportation costs, perforating the well, etc. are a few examples of items that are included in IDC for tax purposes.[2]

As noted above, working interest owners have the option to deduct IDC. This is done by claiming the deduction in the first taxable year in which these types of costs are incurred. Once an election to expense IDC is made, it is binding on all subsequent tax years. If a deduction is not taken, you will be deemed to have capitalized IDC, and costs will be recovered through depreciation expense for tax purposes. Filing an amended return to a timely filed return will not change the election for tax purposes. Additionally, there are rules regarding domestic versus foreign intangible drilling costs that may subject you to one treatment of IDC over another. For this reason, it is important to consult with a CPA to determine the most advantageous treatment of IDC.

The tax risk with respect to IDC exists because taxpayers sometimes overstate expenses in order to lower overall taxable income. For this reason, the examiner is looking for two main things when auditing IDC. First, whether the election to deduct IDC was properly made, and second, whether the costs are appropriately classified as IDC rather than a depreciable asset. To make these assessments, the examiner performs the following procedures on IDC:

1. Determine if you have made a proper election to deduct IDC as a current expense.
2. Test the larger deductions in the intangible development expense account.
    a. Schedule large amounts.
    b. Request invoices.
    c. Request AFEs.
    d. Compare these documents with amounts claimed.
3. Inspect the drilling contracts on a sample basis, especially for December deductions.
4. Determine if prepaid IDC is required by the contract, or if it is merely a deposit, and whether or not it was paid directly to the drilling contractor.
    a. Determine when the well was "staked" and when work was started.
    b. Consider the effect of an adjustment since this could impact the net income limitation for percentage depletion.

[2] For more examples of IDC, see audit technique guide for oil and gas taxpayers at http://www.irs.gov/pub/irs-mssp/oilgas.pdf.

5. Scan the depletion schedules to determine which newly acquired leases are productive.
    a. Look to see if the drilling costs have been shown as a deduction on the leases for the 50 percent percentage depletion limitation.
    b. Prepare a list of new productive leases from the depletion schedule.
6. Request the lease files on all new productive leases, or perform a sample if the total number of new productive leases is large.
    a. Review the lease files to determine if your ownership corresponds with the amount of TDC deducted.
    b. Review assignments, correspondence, and related documents to determine if you have drilled for your interest in the lease, and if you are "carrying" other owners.
    c. Look to see if you handled the transactions correctly.
7. Scan the producing lease account in the asset section of the G/L detail.
    a. Note the leases that have been removed and verify if these items have been reported as sales.
    b. Look to see if any IDC should be recaptured.
8. Allocate a reasonable amount of administrative overhead costs to IDC for tax preference purposes before computing the minimum tax.
    a. The examiner will often request your workpapers to determine if the OH allocation is reasonable.
9. Verify your working interest ownership percentage to determine how much of the IDC you are allowed to deduct in a carried interest arrangement if applicable.
10. Look to see if surface casing has been deducted as IDC. Although it is unsalvageable, it is considered a tangible drilling cost.
11. Look to see if IDC has been shown in operating expenses incorrectly to avoid minimum tax under IRC section 57 or recapture under IRC section 1254.

Lease and Well Equipment

Lease and well equipment is the tangible equipment used in the production of oil and gas. These items have a salvage value and are capitalized to the appropriate cost center. The cost recovery is then made through depreciation expense deductions over the life of the asset. These costs include surface casing, salt water disposal equipment, tubing, road construction post production, etc. The examiner will concurrently test the classification of tangible drilling costs with IDC audit procedures performed. The G/L detail may be examined to ensure that costs are appropriately classified for tax purposes.

Depletion

Depletion is the cost recovery process of recouping assets that are finite in nature. Since oil and gas does not last indefinitely, taxpayers recover the leasehold costs capitalized to the appropriate producing property through depletion expense. There are currently two methods for computing depletion: the cost method and the percentage method. Taxpayers are required to take the larger of the two methods for deduction purposes. Depletion is calculated on a property by property basis. The cost method is effectively a unit of production method. The percentage depletion deduction is based on a percentage (currently 15 percent) of gross income from the property. Taxpayers must have an economic interest in a property to take a depletion expense deduction. The law further limits taxpayers entitled to a percentage depletion deduction to entities that qualify as independent producers and certain royalty owners. Special rules also apply to transfers of proven properties. This expense serves as a deduction for taxpayers in arriving at taxable income. For this reason, the examiner will test the components used in calculating depletion expense in order to verify that you have not understated taxable income.

Several adjustments may be necessary to arrive at the appropriate depletion base for tax purposes. The examiner will determine the book method of accounting utilized and make any necessary adjustments to the depletion base. Further, additional income items must be appropriately identified and accounted for to calculate the depletion deduction. If you are claiming percentage depletion, the examiner will determine whether you have a preference item for alternative minimum tax. IRC section 57(a)(1) states that each property with excess of percentage depletion over the adjusted basis of the depletion interest at the end of the taxable year is a tax preference item. The depletion deduction is not used in determining the adjusted basis of a property. The examiner will request independent verification of the adjusted basis of depletion property for testing purposes. If you are unable to provide this verification, then all percentage depletion will be considered as a tax preference item.

Self-Employment Income

Non-operating interests are typically passive income and not subject to self-employment tax. However, if these interests are received as a result of some personal services and the value is not taxed when received (1099 work) then self-employment tax must be paid. Overriding royalty interests (ORRI) used in a trade or business is included in self-employment income for tax purposes. Working interests are considered to be active conduct in a trade or business and are subject to self-employment tax regardless of whether you are the actual operator of the well. Minority ownerships in working interests are considered partnerships for statutory purposes. The result is the income from this ownership is subject to self-employment tax. Furthermore, limited partners cannot treat losses claimed on the partnership return as a net loss from self-employment because the share of an item of income or loss of a limited partner is excluded from the self-employment net earnings calculation.

Since there are specific rules regarding the inclusion of items when calculating self-employment tax, the examiner will request a detail schedule of items included on the SE 1040 schedule. The examiner will review the schedule and determine if you have claimed items appropriately. The risk is an understatement of self-employment income for tax purposes, so the examiner will want to ensure that all income is appropriately included and all losses are appropriate for deduction purposes.

Brown, PC represents clients in the Oil and Gas business throughout Texas and across the United States. If you have questions regarding an IRS Audit, please call 888-870-0025 or contact us online for a confidential consultation.