Part 4. Examining Process
Chapter 41. Oil and Gas Industry
Section 1. Oil and Gas Handbook (Cont. 2)

4.41.1 Oil and Gas Handbook (Cont. 2)

4.41.1.3
Production and Operation of Oil and Gas Properties

4.41.1.3.7
Oil and Gas Well Depletion

4.41.1.3.7.2 (10-01-2005)
Cost Depletion

1. The cost depletion deduction is the method used to assure the owner of an oil or gas producing property that he/she will be allowed a tax deduction at least equal to his/her investment in the depleting property as rapidly as the asset is consumed.

2. For computing cost depletion a "unit cost" must first be computed by dividing the taxpayer's adjusted basis by the number of remaining recoverable units of oil and/or gas. The taxpayer's adjusted basis is determined under IRC section 1011. The number of remaining recoverable units for any tax period is the estimated number of recoverable units determined at the end of the tax period plus the number of units produced and sold during the tax period. The unit cost is then multiplied by the number of units sold during the tax period to compute the cost depletion deduction. See Treas. Reg. 1.611-2(a).

3. In certain situations cost depletion can also be based on dollar amounts. For lease bonuses and advanced royalties see Treas. Reg. 1.612-3 (a). In this calculation, the taxpayer's remaining basis is divided by the total remaining gross income expected to be received from the beginning of the tax period to total depletion of the property to calculate a unit cost in dollars cost per expected dollar receipts. The resulting fraction is then multiplied by the tax period's reportable gross income to compute the allowable cost depletion. See Treas. Reg. 1.612–3(a).

4. If a taxpayer receives a lease bonus on wildcat acreage and claims cost depletion equal to 100 percent of his/her cost, this has the effect of claiming the minerals are worthless as they supposedly will produce no future income. Worthlessness must be proven by an event, and no such event has occurred. Further, it is assumed that the lease itself has value or the lessee would not have paid the bonus. Therefore, cost depletion should not be allowed unless it is possible to make a reasonable estimate of future income and that estimated income is not zero. However, for a contrary decision, see *Collums v. United States* , 480 F. Supp. 864 AFTR 2d 80–751 (DC Wyo. 1979) with respect to which no action on decision has been issued. See PLR 8532011 and IRM 4.41.1.3.7.4 for additional details on lease bonuses.

5. For estimates of recoverable units, see IRM *4.41.1.3.7.2.2*, Reserves of Oil and Gas.

6. In large cases with numerous calculations, a taxpayer's calculations can be quickly verified by use of a computer audit specialist.

7. Cost depletion, if it is greater than the allowable percentage depletion, must be allowed in lieu of, but not in addition to, percentage depletion.

4.41.1.3.7.2.1 (07-31-2002)
Depletable Basis

1. As provided in IRC section 612, generally a taxpayer's basis for the cost depletion computation is his/her adjusted basis under IRC section 1011.

2. When a taxpayer purchases an interest in a property and there is only one asset, few problems concerning cost have arisen.

3. Frequently, a problem of basis for cost depletion arises when a taxpayer purchases more than one asset for a lump sum. When a taxpayer purchases a producing lease and related equipment for a lump sum, the allocation of cost between leasehold (depletable) and equipment (depreciable) is controlled by Treas. Reg. 1.611–1(d)(4) and 1.167(a)–5 and Rev. Rul. 69–539, 1969–2 C.B. 141. The cost is allocated between leasehold and equipment based on relative fair market values. However, Treas. Reg. 1.1245–1(a)(5) provide that on the sale of IRC section 1245 property and non-IRC section 1245 property, if the buyer and seller are adverse as to the allocation, any arm's-length agreement between the buyer and seller will establish the allocation. In the absence of such an agreement, the allocation shall be made by taking into account the appropriate facts and circumstances.

4. IRM 4.10.7.4.9 (Whipsaw Issues) suggests that allocation of purchase price is a potential whipsaw situation. When a material amount of tax is involved, every reasonable effort should be made to secure the return of both sides to the transaction to secure consistency in the treatment of the transaction.

5. Allocation of a lump-sum purchase price between leasehold and equipment is usually an engineering problem. The agent should secure as much information as possible before referring for engineering services. At a minimum, he/she should obtain copies of the contracts and purchase agreements along with the taxpayer's allocation method and workpapers for making the allocation, as well as a copy of the taxpayer's engineering report which was used as a guide in purchasing the assets.

6. Allowable depletion deductions reduce the taxpayer's remaining basis for cost depletion computations. Accounts should be maintained so that all capitalized cost and all allowable depletion is accumulated. If costs exceed the depletion reserve (accumulated depletion), the difference is the "remaining basis." The effect of this is that an addition to capital of any asset may be fully offset by previously allowed percentage depletion so that, immediately after a substantial capitalization, the taxpayer's "remaining basis" may be zero. See Rev. Rul. 75–451, 1975–2 CB 330, and Treas. Reg. 1.614–6(a)(3), Example 1.

7. Costs which should be capitalized are purchase price or bonus, attorney fees, abstract fees, commissions or other fees paid in connection with acquisition of the property, IDC, and equipment costs paid in excess of the percentage applicable to the interest owned by the taxpayer [see Treas. Reg. 1.612–4(a)(3)]. Other costs that may affect basis are IDC which the taxpayer has not elected to expense under IRC section 263(c); delay rentals which the taxpayer elects to capitalize; equipment costs which are required to be capitalized under Rev. Rul. 69–332, 1969–1 C.B. 87; and geological and geophysical costs, if the results are favorable (see Rev. Rul 77–188, 1977–1 C.B. 76 and Rev. Rul. 83–105, 1983–2 C.B. 51).

4.41.1.3.7.2.2 (10-01-2005)
Reserves of Oil and Gas

1. "Reserves" as of any date means the number of units which are and expected to be recovered subsequent to that date.

2. In the computation of cost depletion, the "unit" " to be used is the principal unit or units paid for in the products sold. See Treas. Reg. 1.611–2 (a). The unit for oil is barrels and for natural gas it is thousand of cubic feet (MCF). The IRS has traditionally allowed taxpayers to use the unit of the predominate product produced from each property or the "barrels of oil equivalent" which can be obtained by converting MCF's of gas to equivalent barrels by dividing by a conversion factor of approximately 6 MCF per barrel.

3. The estimates of reserves of oil or gas must be made " according to the method current in the industry and in light of the most accurate and reliable information obtainable" [Treas. Reg. 1.611–2(c)(1)]. The estimate (quantity) shall include "developed" or "assured" and "probable and prospective" deposits. Industry definitions of proved reserves (proved developed and proved undeveloped) refer to minerals that are reasonably known, or on good evidence believed to exist when the estimates or determination is made according to the method current in the industry and in the light of the most accurate and reliable information obtainable. All proved categories correspond to reserves described in Treas. Reg 1.611-2(c)(1) and should be included in the recoverable units for computation of cost depletion deduction. The examiner should closely review the taxpayers's reserve estimation, in the light of operations or development work prior to the close of the taxable year, and include additional reserves required by applicable regulation, and consistent with industry standards and supported by taxpayer's actual practices. See the IRS Coordinated Issue Paper, Cost Depletion-Recoverable Reserves.http://www.irs.gov/pub/irs-isp/pet-cost.pdf

4. Effective for tax years ending on or after March 8, 2004 taxpayers may elect to use a "safe harbor" to calculate their total recoverable units. Total recoverable units are generally set equal to 105% of proved reserves (both developed and undeveloped) as defined by the 17 C.F.R. IRC section 210.4-10(a) of Regulation S-X. The safe harbor must be used for all domestic oil and gas properties owned by the taxpayer. See Rev. Proc. 2004-19 and the Field Directive on Cost Depletion – Determination of Recoverable Reserves issued by the Industry Director (Natural Resources and Construction) on July 30, 2004. http://www.irs.gov/businesses/article/0,,id=152595,00.html

5. The "reserves" to be used in the cost depletion computations for any tax period are the "reserves" at the end of that tax period plus the units produced during that tax period. See Treas. Reg. 1.611–2(a)(3). This determination is important because the formula to compute cost depletion is the same as financial accounting. However, the amounts inserted into the various portions of the calculation are different. Care should be taken to assure that adjusting entries are being made to book amounts before tax cost depletion is calculated.

   CD= CP x [ATB/(CP+FP)]

   Where:

ATB =	Amount of depletable tax basis remaining
CD =	Cost Depletion
CP =	Current Production
FP =	Future Production as of end of year

6. IRC section 611(a) provides in any case in which it is ascertained as a result of operations or development work that, if the recoverable units are greater or less than the prior estimate thereof, such prior estimate shall be revised and the depletion allowance under this section for subsequent years shall be based on such revised estimates. For purposes of cost depletion, the taxpayer is not permitted to revise the reserve estimate based solely on economic factors, without operations or development work indicating the physical existence of materially different quantity of reserves than originally estimated to purchase or to develop the property. See *Martin Marietta Corp. v. United States* , 7 Cl. Ct. 586, 85–1 USTC 9284 (Cl. Ct. 1985).

7. The units to be used in the calculation of cost depletion deduction of any taxpayer are only the units which have been and will be produced to the interest owned by that taxpayer.

   Example:

   Taxpayer A owns a royalty of one-eighth of production in Lease Z. Lease Z has produced 8,000 barrels of oil during the current tax period. At the end of the tax period Lease Z contains 80,000 barrels of oil reserves. *Taxpayer A's* units produced during the current tax period are one-eighth of 8,000 barrels or 1,000 barrels. *Taxpayer A's* reserves of oil for cost depletion computation are 11,000-one-eighth of 80,000 barrels plus 1,000 barrels.

8. Making estimates of the reserves of oil or gas is an engineering project. If the agent has a significant problem with respect to reserve estimates, he/she should request engineering services. In most cases when cost depletion deductions are significant, the taxpayer will have "in-house " engineers or outside consultants prepare the estimates of reserves for use by the accounting department. These estimates may be used for full cost accounting financial statements and/or tax computations. It is important to understand that the circumstances under which a reserve estimate may be changed for tax purposes are different from circumstances under which reserves can be changed for financial reporting purposes. The agent should obtain copies of these estimates and forward them to the engineer with the request for engineering services. Engineers should refer to IRM *4.41.1.3.7.2.3.* , Appropriate Additional Reserves of Oil and Gas.

9. If a taxpayer's cost depletion approaches or exceeds 50 percent of the net taxable income from the property or the cost per barrel of oil produced appears excessive, the agent should investigate the facts concerning the acquisition of the property and the basis in the property. There may be errors in the allocation of cost, estimation of reserves, or basis claimed. Units claimed produced for depletion purposes may be in excess of those reported for income reporting purposes. Sometimes assets transferred between subsidiaries may have been transferred at "book" rather than tax basis. Assets transferred between subsidiaries may have been transferred at tax cost, but the related reserve accounts may not have been transferred. IDC which were expensed for tax purposes may have been capitalized for " book" and cost depletion purposes. In years that percentage depletion exceeded cost depletion the excess percentage depletion may not have been deducted from cost basis.

4.41.1.3.7.2.3 (01-01-2005)
Appropriate Additional Reserves of Oil and Gas

1. Disputes with taxpayers often arise in determining the quantity of "probable" or "prospective" reserves to be included in a property's total recoverable units from oil and gas wells for purposes of computing cost depletion under IRC section 611 of the Internal Revenue Code.

2. Under IRC section 1.611-2 of the Income Tax Regulations, if it is necessary to estimate or determine with respect to any mineral deposit as of any specific date the total recoverable units 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. 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:

   - The ores and minerals "in sight" , " blocked out" ,"developed" , or"assured " , in the usual or conventional meaning of these terms with respect to the type of the deposits, and

   - "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:

- 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

- As to grade, only in accordance with the best indications available as to richness.

3. The minerals primarily produced in the petroleum industry are liquid and gaseous hydrocarbons. These are commonly referred to as oil, gas, and natural gas liquids. Some byproducts such as carbon dioxide and sulfur are also produced. Recoverable units or reserves volumes for hydrocarbons are usually reported as barrels (BBL) for liquids and thousands of cubic feet (MCF) for gases by domestic companies. Reserves may also be recorded in terms of barrel of oil equivalents (BOE) where the gas has been converted to an equivalent liquid volume (based of BTU content) and added to the oil reserves. International companies may use other units of measure for reserves in foreign locations. Examiners/engineers need to be aware that there are variations in reserve volume nomenclature, that standard conditions of volume measurement vary somewhat, and that conversion of gas volume to oil volume may be a source of error in determining hydrocarbon reserves

4. IRS examiners/engineers must follow the Coordinated Issue Paper "Cost Depletion-Recoverable Reserves" . According to the Coordinated Issue Paper, the taxpayer must include all proved reserves (both developed and undeveloped) in the cost depletion calculation. In addition, the taxpayer must include "appropriate additional reserves" which are generally referred to as probable reserves. The Coordinated Issue Paper also restates long-standing IRS policy that reserves estimates may not be revised solely because of changes in economic conditions.

5. To minimize disputes over probable reserves, the IRS promulgated a safe harbor that taxpayers can elect for tax years ending on or after March 8, 2004. See Rev. Proc. 2004-19 and IRM *4.41.1.3.7.2.2* .

4.41.1.3.7.2.3.1 (01-01-2005)
Problems in Determining Recoverable Reserves:

1. Determining the correct quantity of recoverable units for cost depletion can be a challenging task. Examiners will likely find each taxpayer to have unique business records and practices related to the estimation and compilation of oil and gas reserves. In addition taxpayers may use terms that have a specific meaning to them, but different meanings to others. Examples include:

   - Reserves, recoverable units, expected ultimate recovery
   - Probable, prospective, possible, potential
   - Non-producing, undeveloped, noncommercial, static
   - Likelihood, reasonable certainty, confidence, probability

2. Taxpayers estimate, compile, utilize, and report reserves in different ways for different purposes. Taxpayers may have reserve estimates for internal purposes different from those reported to the IRS. Taxpayers may consider "static reserves" to be reserves that are proved in the technical sense, but not commercially recoverable due to economic or political reasons.

3. For the same occurrence (or anticipated occurrence) of oil and gas, taxpayers may determine different quantities associated with different categories. For example, the quantity of "unrisked" probable reserves may be higher than the "most likely" probable reserves.

4. Taxpayers may estimate proved reserves down to the property level, but unproved reserves only down to the field level. Taxpayers may also have estimates of unproved reserves that are not in a ledger format, but instead are contained in analyses of specific property acquisitions.

5. Examiners are likely to find that no "appropriate additional reserves" have been incorporated by the taxpayer in its cost depletion computation.

6. Publicly traded oil companies must annually submit an estimate of their proved reserves (both developed and undeveloped) to the Securities and Exchange Commission (SEC). Many taxpayers use these same reserves for cost depletion. However, some taxpayers exclude subcategories such as proved undeveloped reserves or proved non-producing reserves. SEC reserves can be very susceptible to negative changes in economic conditions, and may be less than the true proved reserves for particular properties. The SEC's reserves definitions are contained in Reg. section 210.4-10 of Regulation S-X of the Securities Exchange Act of 1934. http://ecfr.gpoaccess.gov/cgi/t/text/text-idx?c=ecfr&sid=20c66c74f60c4bb8392bcf9ad6fccea3&rgn=div5&view=text&node=17:2.0.1.1.8&idno=17#17:2.0.1.1.8.0.21.42

7. Companies are also required by law to annually report to the Energy Information Administration (EIA) an estimate of proved reserves in the U.S. Examiners should be aware of the peculiarities of this data -

   - Each company reports reserves for only those properties that it operates
   - The reserves are reported by field, not by specific lease or property
   - The reserves are reported on an "8/8th" basis; therefore they are not net to the company's ownership interest.

   The EIA treats this information as proprietary, so examiners would have to obtain this information from the taxpayer. The EIA's definition of proved reserves is very similar to that of the Society of Petroleum Engineers (SPE). http://www.eia.doe.gov/pub/oil_gas/natural_gas/survey_forms/eia23li.PDF

8. The Society of Petroleum Engineers (SPE), in conjunction with the World Petroleum Congress (WPC), has promulgated reserves definitions. To promote consistency of examinations, examiners/engineers should become familiar with the following: http://www.spe.org/industry/reserves/

   - Society of Petroleum Engineers and World Petroleum Congress - Petroleum Reserve Definitions.
   - Society of Petroleum Engineers and World Petroleum Congress - Petroleum Resources Classification and Definition
   - Society of Petroleum Engineers - Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information.

9. The SPE definitions and classifications have been drafted in great detail. The key concepts can be seen by the following excerpts -

   - Reserves are those quantities of petroleum which are anticipated to be commercially recovered from known accumulations from a given date forward.
   - Proved reserves are those quantities of petroleum which, by analysis of geological and engineering data, can be estimated with

reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods, and government regulations. Proved reserves can be categorized as developed or undeveloped.

- Unproved reserves are based on geologic and/or engineering data similar to that used in estimates of proved reserves; but technical, contractual, economic, or regulatory uncertainties preclude such reserves being classified as proved. Unproved reserves may be further classified as probable reserves and possible reserves.
- Probable reserves are those unproved reserves which analysis of geological and engineering data suggests are more likely than not to be recoverable.
- Possible reserves are those unproved reserves which analysis of geological and engineering data suggests are less likely to be recoverable than probable reserves.

10. The Society of Petroleum Evaluation Engineers (SPEE) is also a good source of information on estimating oil and gas reserves. www.spee.org

11. IRS petroleum engineers have concluded that as a factual matter:

    - The SPE's definition of proved reserves refers to minerals described in Treas. Reg. section 1.611-2(c)(1) in that they are "reasonably known, or on good evidence believed to exist." SPE proved reserves (both developed and undeveloped) should be included in the cost depletion calculation.
    - The SPE's definition of probable reserves is generally consistent with minerals described in Treas. Reg. section 1.611-2(c)(1)(ii). They are reasonably analogous to "probable and prospective" ores or minerals. SPE probable reserves should be included at the appropriate time in the cost depletion calculation as discussed further in the Analysis of SPE Factual Scenarios of Probable Reserves that follows.
    - The SPE's definition of possible reserves is generally not consistent with minerals described in Treas. Reg. section 1.611-2(c)(1). Their low level of confidence is not consistent with minerals that are "reasonably known, or on good evidence believed to exist." or those that are "probable and prospective" . Generally, SPE possible reserves should not be included in the cost depletion calculation.

4.41.1.3.7.2.3.2 (01-01-2005)
Analysis of SPE Factual Scenarios of Probable Reserves

1. The SPE's reserves definitions includes a description of several factual scenarios for probable reserves. IRS petroleum engineers analyzed each factual scenario and determined -

    - Whether the described scenario meets the criteria of Treas. Reg. section 1.611-2(c)(1);
    - What quantity of probable reserves should be included in the cost depletion calculation; and
    - When the probable reserves should be included in the cost depletion calculation

    The factual scenarios are universal in nature and provide a good reference point for examiners/engineers. In this analysis, the terms reserves, proved reserves, and probable reserves carry the same meaning as the complete SPE definition of these terms. Examiners/engineers should be cognizant that any particular taxpayer's definition of these terms may differ from the SPE's. The complete analysis is contained in Exhibit 4.41.1-26.

4.41.1.3.7.2.3.3 (01-01-2005)
Planning and Case Management

1. Case Management. During the planning phase of the examination, the examiner/engineer should brief management regarding the taxpayer's compliance with Treas. Reg. section 1.611-2(g)(1). If prior examination histories demonstrate a pattern of the taxpayer disregarding the regulation's record keeping requirements, the examiner/engineer should seriously consider issuing an Inadequate Record Notice to the taxpayer. If records exist, but the taxpayer will not cooperate in providing information in a timely manner that will assist in the factual development of the reserves issue, the examiner/engineer should obtain appropriate approval to request assistance from Counsel in summonsing the information.

2. Engineer Involvement. Verifying reserves is within the purview of engineering specialists. Revenue agents should refer all identified cost depletion issues to a petroleum engineer. Mandatory referral criteria are set forth in the Internal Revenue Manual. When cost depletion deductions are significant, the taxpayer will normally have "in-house" engineers or outside consultants prepare the reserve estimates for use by the taxpayer's accounting department. The taxpayer may use these estimates for full cost accounting financial statements and/or for tax. The revenue agent should obtain copies of these estimates and forward them to the engineer with the request for engineering services.

3. The taxpayer may have hundreds or thousands of properties for which it claims depletion, and the information given to the agent in a machine sensible format may not be in an Excel (spreadsheet) or Access (database) format. If possible, the revenue agent should request a Computer Audit Specialist (CAS) to put tax depletion and/or reserves schedules in an Excel or Access format. If a referral to an engineer is necessary, this should be done as early as possible. This will allow the engineer to request these files after consultation with the taxpayer and the CAS as to the best format. Otherwise, there may be delays in the examination.

4. Information To Be Requested at the Outset of the Examination. The examiner/engineer should request the following information from the taxpayer at the outset of the examination:

    - Detailed tax depletion ledger by tax property, which should include an explanation of the headings. The taxpayer should provide the ledger in hard copy and electronic record format if possible;
    - A reconciliation of the tax return amount to the detailed tax depletion schedule. The taxpayer should provide the reconciliation in hard copy and electronic record format if possible;
    - Detailed reserves and production ledger which shows all reserves, changes to reserves, and annual production by property. Taxpayers may have multiple estimates of reserves (e.g. different categories or different estimates of the same category) and all estimates should be specifically requested. If may be necessary to inquire as to what reserves estimates are maintained by the taxpayer;
    - A reserves handbook or reserves manual that describes how the taxpayer defines all of its different categories of reserves and what reserves the taxpayer considers recoverable;
    - Third party (independent) reserves report(s) prepared for the taxpayer;
    - Separate property election statements; and

- The accounting manual covering depletion and/or depletion record keeping for the years under examination.

5. Information To Be Requested on an "As Needed" Basis. The examiner/engineer should request the following information on an "as needed basis" on specific properties selected for examination:

   - Reconciliation of annual lease production [revenue];
   - Reconciliation of leasehold basis and basis additions;
   - Structure and isopach maps;
   - Well logs, well data;
   - Unitization agreements;
   - Lease abandonment report;
   - Like - kind exchange property agreements;
   - Lease sale agreements;
   - Gas contract agreements;
   - Partnership agreements;
   - Appraisal reports performed for the purposes of sales/purchases of properties; and
   - Energy Information Administration (EIA) reports submitted by the taxpayer to the Department of Energy. See IRM 4.41.1.3.7.2.3.1(7) for further discussion of these reports.
   - For foreign properties the examiner/engineer should request -

     A. copies of contracts associated with the property, including, but not limited to, exploration, development, production sharing, and risk services agreements;

     B. for properties subject to term renewable contracts -

        1. remaining term,
        2. contract area, renewable clauses,
        3. and current efforts to renew or renegotiate contract.

     C. copy of a current accounting manual covering depletion;

     D. documentation which identifies property units;

     E. documentation which identifies changes to reserve estimates due solely to economics.

6. Access to Taxpayer Personnel. The engineer should request the identification and use of the following taxpayer personnel:

   - A person with knowledge of reserve accounting;
   - An engineer with knowledge of all of the taxpayer's reserve categories associated with specific properties; and
   - A liaison with personal knowledge of the computer system(s) used to compile the data for the taxpayer's cost depletion file. The computer systems include, but are not limited to, those housing the depletion schedules, recoverable reserve schedules, revenue and expense ledgers, production data, etc.

7. Treas. Reg. sections 1.611-2 and 1.611-3 provide a list of data that taxpayers should have readily available to support its depletion deduction.

4.41.1.3.7.2.3.4 (01-01-2005)
Conducting the Reserve Examination

1. The engineer should understand the source and descriptions of all of the information in the taxpayer's reserve and depletion ledgers. The engineer should also read the Coordinated Issue Paper "Cost Depletion-Recoverable Reserves" and the most recent promulgations of the SPE regarding petroleum reserve definitions, resources classifications, and estimating standards.

2. After reconciling the tax depletion amount to the tax depletion schedules and receiving any requested information, the engineer should analyze the depletion schedules and select those properties composing the majority of the deduction for an in depth review. Criteria to consider in making a selection of properties for detailed review include (but are not limited to):

   - Properties with high depletion rates. Depletion rate is the fraction or percentage that is multiplied by remaining basis to arrive at cost depletion for the year. Although there are no strict guidelines, many engineers would consider a high depletion rate to be 10 percent for onshore properties, and 20 percent for offshore Gulf of Mexico properties;
   - Properties with material changes in reserve estimates (especially reductions);
   - Properties with material changes in depletion basis (especially deletions to basis);
   - Properties in the first few years of production; and
   - Properties recently farmed out/in, unitized, sold, acquired, or exchanged.

3. The identity of these properties may have to be requested from the taxpayer via an Information Document Requests (IDR). Other sources of

information include:

- Comparative analyses for current and prior cycles;
- Certain forms attached to the tax return e.g. Form 4797 (Sales of Business Property) and Form 8824 (Like-Kind Exchanges); or
- The revisions to reserves that should be available in the taxpayer's reserves ledgers. The ledgers of many taxpayers incorporate a series of "codes" to identify the nature of any revision to reserves, including those due solely to economics. An explanation of the codes should be obtained.

4. The engineer should determine what year-end reserves the taxpayer has included in its cost depletion calculation. The reserves might be the same as those submitted to the SEC, or they might be another figure based on company-specific guidelines. In either case the engineer should determine whether the taxpayer excluded any category of proved reserves, such as proved undeveloped or proved non-producing. The engineer should determine how the taxpayer defines, estimates, and compiles its unproved reserves. If it uses the terms "probable " or "prospective" it may not necessarily define them in a manner that is consistent with the regulations. The engineer should also compare them to the SPE petroleum reserves definitions.
5. The engineer should determine how the taxpayer's unproved reserves relate to its expected ultimate recovery. Unproved reserves are sometimes presented along with an associated probability of success. Engineers should determine if the quantity of unproved reserves already reflects the probability of success. The engineer may consider analyzing the unproved reserves for each of the selected properties under Treas. Reg. section 1.611-2 by referring to the Society of Petroleum Engineers' Probable Reserves Factual Scenarios. See Exhibit 4.41.1-26. If the engineer has any questions while conducting this analysis, the engineer should contact the taxpayer's reservoir engineer.
6. After the engineer determines what quantity of unproved reserves should be included in the cost depletion calculation, the engineer should obtain and/or determine the appropriate unproved reserves on a property basis. If the taxpayer determines probable reserves only on the field level, then the engineer should allocate the reserves back to the property level on a proved reserve basis, or other reasonable method. The engineer should then recalculate the cost depletion for each of the selected properties by adding the appropriate unproved reserves to the year-end proved reserves in the denominator of the cost depletion formula.
7. For foreign properties, there are a variety of unique problems than can affect depletion. There may be issues involving property concepts, term contracts that may or may not have renewal clauses, production sharing agreements, economic/pricing issues, and political constraints. If the engineer has questions concerning these issues he or she should consult other engineers with foreign depletion experience. The Petroleum Industry Program (PIP) coordinated issue paper on North Sea IDC Transition Rule describes some of these contractual arrangements. As with any issue related to a foreign entity, the engineer should consult the international examining agent.
8. If the engineer has further questions, he or she should contact the IRS Petroleum Industry Program or Petroleum Industry Specialist.

4.41.1.3.7.2.3.5 (01-01-2005)
Issues Related to Cost Depletion:

1. Examiners should ensure the following:
   - That depletion is computed on a property by property basis;
   - The proper allocation of basis (including both depreciable and depletable) in the acquisition of multiple properties for a lump sum;
   - That the accounting systems properly match sales (usually production) and estimated reserves for each property. This information is often imported into the depletion ledger from different information systems;
   - That depletion deductions and abandonment losses are properly coordinated, so that no amount of basis is deducted twice;
   - That cumulative depletion for each property is tracked so that depletion recapture under IRC section 1254 can be properly reported;
   - That they conduct a close review of any deletions from depletable basis;
   - That any additions to depletable basis are added to the original basis and not to the remaining basis under Revenue Ruling 75-451, 1975-2 C.B. 330; and
   - That separate property elections are properly followed.

4.41.1.3.7.3 (07-31-2002)
Percentage Depletion

1. The percentage depletion deduction is computed as a percent of gross income from the property, limited to the net taxable income from the property. For this reason, the definition of gross income from the property is very important. See IRM *4.41.1.3.5.1.3*.
2. Percentage depletion is allowed under IRC section 613, but with the passage of the Tax Reduction Act of 1975 (effective January 1,1975, and applicable to years ending after December 31,1974), percentage depletion is restricted for oil and/or hydrocarbon gas as provided in IRC section 613A. IRC section 613A is quite complex and restrictive and should be studied carefully by the agent. The *Basic and Advanced Oil and Gas Textbooks* (Texts 3185–03 and 3186–04) provide a good discussion of IRC section 613A. Refiners and retailers (as defined in IRC section 613A(d)(2)) are not allowed percentage depletion on oil or hydrocarbon gas, except as provided in IRC section 613A(b).

4.41.1.3.7.3.1 (07-31-2002)
Property Unit

1. The definition of "the property" is very important in the computation of the allowable percentage depletion.
2. The gross income from the property must include all depletable income to the property for the tax period and may not include income from any other property or source.
3. Expenses deducted in determining net income and 50 percent (100 percent for taxable years beginning after December 31, 1990) of net taxable income must include all expenses of the property and may not include any negative expenses or other income as offsets against expense of that property.

4.41.1.3.7.3.2 (10-01-2005)
Property Defined

1. The term "property" means each separate interest owned by the taxpayer in each mineral deposit in each separate tract or parcel of land [IRC [IRC section 614(a)].

2. If there is no known mineral deposit under a tract or parcel of land, for property definition it is treated as if it had one deposit.

3. The definition is very simple. However, its use in practice can become extremely complicated because of its importance and the many and various ways in which property owners, by contract, agree to divide or unitize income and/or operating expenses.

4. "Separate interest" refers to a type of interest. See Rev. Rul. 77–176, 1977–1 C.B. 77. The interest may be a working interest, royalty, overriding royalty, production payment, net profits interest, or mineral interest owned in fee.

5. "Each mineral deposit" refers to minerals in place. See Treas. Reg. 1.611–1(d)(4). With respect to oil and gas wells, each separate mineral deposit refers to each separate subsurface naturally occurring accumulation of oil and/or gas which is separate and apart from and not in naturally occurring communication with any other such accumulation of oil and/or gas.

   Example 1. Two potential oil productive zones — Devonian and Ellenburger, exist under Tract A, a large undrilled tract of land. There are no other productive zones, and it is not known if either Devonian or Ellenburger zones will produce oil or gas in commercial quantities. Tract A has no mineral deposit.

   Example 2. The facts are the same as in Example 1 except that a well is drilled on the south side of Tract A to the Devonian, and it now produces oil. Tract A has one mineral deposit.

   Example 3. Facts are the same as Example 2 except that the well was deepened to the Ellenburger, and that zone now also produces oil. Tract A has two mineral deposits.

   Example 4. Facts are the same as Example 3 except that an offset to the first well has been drilled, and it produces oil from both Devonian and Ellenburger zones. Tract A has two mineral deposits.

   Example 5. Facts are the same as Example 4 except that an additional well has been drilled on the north side of the tract, and it also produces from the Devonian and Ellenburger zones. Also, two additional wells have been drilled between the wells on the south side of Tract A and the well on the north side of Tract A. These wells penetrated both Devonian and Ellenburger zones and found them barren of oil. Geological studies now indicate that the wells on the south side and north side are not producing from the same structure, and the mineral deposits are not continuous across the tract. Tract A has four mineral deposits.

6. "Each separate tract" refers to the physical area and is delineated by legal description; i.e., part of section, section number, block or township and range, survey, county or parish, and state. All contiguous areas, even though separately described, included in a single conveyance or in separate conveyances at the same time from the same owner constitute a single tract or parcel of land. See Rev. Rul. 68–566, 1968–2 C.B. 281, for contiguous Government leases acquired on the same bid and Examples 8 and 9 of Treas. Reg. 1.614–1 (a), for contiguous leases not originating as a single tract or parcel of land.

7. The criteria for tax property given previously referred to each mineral deposit. The regulations make it clear that interest in each separate mineral deposit, under a tract or parcel of land, constitutes a separate interest. Although each separate mineral interest is a separate property such separate mineral interests, under the same tract or parcel of land are considered to be "one property" unless the taxpayer elects to treat the separate properties. See Treas. Reg. 1-614-1(a)(3).

8. In practice the agent has to determine the taxpayers separate properties. Some taxpayers treat separate "wells" as separate properties. One tax property can have several wells and all the production, income, and expenses needs to be combined to compute depletion for that property. As stated above the computation of percentage depletion is "off book" , therefore production, income, and expenses can be reallocated by taxpayers to improper properties to maximize the percentage depletion deduction. The taxpayer's "lease files" and AFE's are a good source to determine if misallocations are present.

4.41.1.3.7.3.3 (07-31-2002)
Separate Acquisitions of Contiguous Leases

1. If contiguous leases are acquired at the same time from different land owners or at different times from the same land owner, the leases constitute separate tracts and, therefore, separate properties. See Treas. Reg. 1.614–1(a)(3).

   Example 1. K. Hayes owns all the minerals in the east half of section 2 (320 acres), and H. Curry owns all the minerals in the west half of the same section 2 (320 acres). Together they meet with C. Dillon on January 13, 1978, and both K. Hayes and H. Curry sign the same oil and gas lease agreement which, in effect, leases all of section 2 to C. Dillon. The agreement is not a unitization agreement within the meaning of Treas. Reg. 1.614–8(b). C. Dillon has two properties.

   Example 2. K. Hayes owns all the minerals in section 2 (640 acres). On January 13, 1978, K. Hayes leases the east half of section 2 for oil and gas to C. Dillon. On May 31, 1978, in a transaction unrelated to the January 13 transaction, K. Hayes leases the west half of section 2 for oil and gas to C. Dillon. Both K. Hayes and C. Dillon have two properties.

4.41.1.3.7.3.4 (07-31-2002)
Acquisition—Additional Working Interest

1. Each separate acquisition of a working interest in a parcel or tract of land constitutes a separate property.

   Example:

   On January 3, 1978, H. Curry owned one-half and K. Hayes owned one-quarter of the working interest in section 5; C. Dillon owned one-quarter of the working interest in the same section 5. Only one oil deposit is known to underlie section 5. On June 30, 1978, C. Dillon purchased all of H. Curry's working interest in section 5 for $100,000. On December 26, 1978, C. Dillon purchased all of K. Hayes' working interest in section 5 for $100,000. On December 26, 1978, C. Dillon had three properties in section 5.

4.41.1.3.7.3.5 (07-31-2002)
Multiple Producing Zones

1. Two or more producing zones in one well—each separate producing zone constitutes a separate mineral deposit and, therefore, a separate property.

4.41.1.3.7.3.6 (07-31-2002)
Separate Mineral Interest Election

1. Notwithstanding the preceding definition of a property, if a taxpayer has two or more operating mineral interests (also known as working interest) located on a tract or parcel of land and if he/she wishes to treat them as separate properties, he/she must make an election to treat them separately. Any operating mineral interests located on a single tract or parcel of land for which no separate property treatment election has been made will be combined and treated as one property. See Treas. Reg. 1.614–8(a)(1).

2. The election described in (e) (1) above must be made by a statement attached to the tax return for the first taxable year beginning after 1963 or the first taxable year in which any expenditure for development or operation, in respect to an operating mineral interest, is made by the taxpayer after his/her acquisition of the interest. See Treas. Reg. 1.614–8(a)(3).

4.41.1.3.7.3.7 (07-31-2002)
Unitizations

1. If one or more of a taxpayer's operating mineral interests, or a part or parts thereof, participate under a unitization or pooling agreement in a single cooperative or unit plan of operation, then for the period of such participation in taxable years beginning after December 31, 1963, such interests included in such unit shall be treated as one property, separate from the interests not included in such unit [Treas. Reg. 1.614-8(b)(1)].

2. The term "unitization or pooling agreement" means an agreement under which two or more persons owning operating mineral interests agree to have the interest operated on a unified basis and agree to share in production on a stipulated percentage or fractional basis regardless of from which interest the oil or gas is produced. If one person owns several leases, an agreement of such person with his/her royalty owners to determine the royalties payable to each on a stipulated percentage basis regardless from which lease oil or gas is obtained is also a unitization or pooling agreement.

3. When partially or fully developed leases are unitized for further development and/or secondary recovery operations, there may be equalization payments involved. Some leases which are being unitized may be fully developed with all well sites drilled, while other leases would require additional intangible drilling and equipment costs to enter the unit on an equal basis with the fully developed leases. The organizer of the unit (usually the designated unit operator) will normally prepare a schedule of the relative developed condition of each of the leases. This condition is stated in terms of dollar value of equipment and previously expended IDC. A weighted average per drill site is computed for the unit. Each lease is then assigned two values for equipment and intangible drilling costs.

    A. The unit weighted average per drill site multiplied by the number of drill sites on the lease

    B. The lease's value of equipment and previously expended intangible drilling costs in its condition as the lease enters the unit

4. If the value of a lease determined in (b) is greater than the value determined in (a), the owners of that lease will be entitled to receive the dollar value difference. If the value of a lease determined in (b) is less than the value determined in (a), the owners of that lease must pay the dollar value difference.

5. Payment is usually made by either one of two methods.

    - Cash payments

    - Increase the percentage of revenue to the lease owners due payment and decrease percentage of revenue to the others until equalization has been achieved

6. The cash payments received are considered as boot in a tax-free exchange of property; IRC sections 1031, 1231, 1245, and 1254 must be considered.

7. Frequently, the payor of the cash payments will deduct the payments either as IDC [IRC section 263(c)] or as operating expenses [IRC section 162(a)]. These payments are capital investments in either leasehold or equipment. *See Platt v. Commissioner* , 18 T.C. 1229 (1952); affd, 207 F.2d 697 (7th Cir. 1953); 44 AFTR 530; 53–2 USTC 48,515. The payment for equipment does not constitute a purchase of used Section 38 property. See Rev. Rul. 74–64 1974–1 C.B. 12. Therefore, the investment tax credit cannot be claimed by the purchaser.

8. When possible, the agent should compare the taxpayer's depletion computation schedule for the prior and subsequent years. The addition of a property with the word unit in its name might indicate a current unitization The deletion of one or several properties, which appeared to be making a profit, and the addition of another might indicate a current unitization. Auditing the IDC will show the source of these costs. The agent should study the taxpayer's lease acquisition files and well files to determine each reported property's status. In scanning the depletion schedule, if the agent finds separate leases with the same royalty owner's name, he/she should decide if combining the computations into one would have a tax effect. If so, he/she should check lease and well files and/or discuss with the taxpayer to determine property status. If the agent has reason to believe a property has been unitized and it might make a tax difference, he/she should inspect a current oil and gas map. Frequently, the map company will indicate units on the map by outlining with dashed lines.

4.41.1.3.7.3.8 (07-31-2002)
Percentage Depletion in Case of Oil and Gas Wells

1. As indicated in IRM *4.41.1.3.5.1.2*, subsequent to 1974, no percentage depletion for oil and gas under IRC section 613 is allowable except as provided in IRC section 613A.

2. IRC section 613A states the conditions under which owners of interests in domestic hydrocarbon oil and gas wells and independent producers and royalty owners are allowed to compute and deduct percentage depletion for oil and/or gas production under IRC section 613.

4.41.1.3.7.3.9 (10-01-2005)
Exemption for Certain Domestic Gas Wells

1. IRC section 613A did not affect the computation of percentage depletion for two statutory categories of gas that were prevalent in the mid-1970's, but which are virtually non-existent today due to the passing of time:

    A. Natural gas sold under a fixed price contract, and

    B. Regulated natural gas

4.41.1.3.7.3.10 (07-31-2002)
Depletion Allowable to Independent Producers and Royalty Owners

1. Except for the 65 percent of taxable income limitation, as provided in IRC section 613A(d)(1), a taxpayer who qualifies is allowed to compute and deduct percentage depletion under IRC section 613 with respect to so much of his/her average daily production of domestic crude oil and so much of his/her average daily production of domestic natural gas as does not exceed depletable oil and gas quantities. Retailers and refiners, as defined in IRC sections 613A(d)(2) and (4), do not qualify. See paragraphs (10) and (11) below.

2. For any tax year, a taxpayer's average daily oil production and average daily gas production is determined by dividing his/her total crude oil

production and total gas production by the number of days in that tax year. In making this computation, the taxpayer's production of oil and gas resulting from secondary or tertiary processes will not be taken into account. In making this calculation, the taxpayer's production for which depletion is allowable under IRC section 613A(b) (gas sold under a fixed contract and regulated natural gas) and production from any proven property transferred after 1974 and before October 12, 1990 will not be taken into account (see IRC section 613A(c)(9) for definition of proven property). Before January 1, 1984, secondary and tertiary properties qualify for percentage depletion from proven properties transferred after December 31, 1974.

3. For any tax year, a taxpayer's depletable gas quantity is 6,000 cubic feet multiplied by the number of barrels of the taxpayer's depletable oil quantity which the taxpayer elects to convert to depletable gas quantity.

4. Effective January 1,1990 the depletion rate for oil and gas produced by primary, secondary and/or tertiary methods or processes attributable to independent producers and royalty owners is 15 percent.

5. The tentative quantity specified in IRC section 613A(c)(3)(B) is currently 1,000 BBL.

6. Beginning after December 31, 1990, a 15 percent depletion rate for marginal oil or gas production properties held by independent producers or royalty owners increases by 1 percent (up to a maximum 25 percent rate) for each whole dollar that the reference price for crude oil for the preceding calendar year is less than $20 per barrel. See IRC section 613A(c)(6). Notice 2003-44, I.R.B. 2003-28, 52, contains the relevant percentages for calendar years 1991 through 2003.

7. In applying IRC section 613A to fiscal-year taxpayers, each portion of such fiscal year which occurs within a single calendar year shall be treated as if it were a short taxable year. See Treas. Reg. 1.613A–3(k).

8. For purposes of the depletable oil or gas quantity limitations, component members of a controlled group of corporations, as defined in Treas. Reg. 1.613A–7(1), are treated as one taxpayer. The group shares the one depletable oil or gas quantity. Secondary production of a member of the group will reduce the other members' share of the group's depletable quantity. The depletable oil quantity remaining is then allocated among the entities in proportion to production of barrels of oil and gas (converted to BBL of oil at 6,000 cubic feet = 1 BBL of oil). For purposes of the depletable oil or gas quantity limitation, a family group (which consists of an individual, spouse, and minor children) will be allowed only one tentative oil quantity as shown in IRC section 613A(c)(3)(B). The tentative oil quantity is allocated among the individuals in proportion to their respective production of oil and gas (converted to BBL of oil at 6,000 cubic feet =1 BBL of oil).

9. IRC section 613A(c) does not apply to retailers as defined in Treas. Reg. 1.613A–7(r). See IRC section 613A(d)(2). A retailer is a taxpayer who directly, or through a related person, sells oil or natural gas or any product derived from oil or natural gas through any retail outlet or outlets; and the combined gross receipts exceed $5,000,000 during the taxable year.

10. IRC section 613A(c) does not apply to refiners as defined in Treas. Reg. 1.613A–7(s). See IRC section 61 3A(d)(4). A person is a refiner if such person or related persons engages in the refining of crude oil and if the total refinery runs of such person and related persons exceed 50,000 BBLS on any one day during the taxable year (75,000 BBLS for tax years after the enactment of the "Energy Tax Incentives Act of 2005").

11. A taxpayer's total percentage depletion deduction under IRC section 613A(d) may not exceed 65 percent of the taxable income for the year, as adjusted. See IRC section 613A(d)(1). "As adjusted" means to eliminate the effects of:

    A. Any net operating loss carryback (IRC section 172)

    B. Any capital loss carryback (IRC section 1212)

    C. In the case of a trust, any distributions to its beneficiaries. [For a very limited exception in case of a trust, see Treas. Reg. 1.613A–4(a)(iv).] See Exhibit *4.41.1-6* for example. For computation of the 65 percent of taxable income limitation with respect to a corporation entitled to a deduction for dividends received under IRC section 243, see IRS Letter Ruling reprint 7902021.

12. The amount of depletion disallowed pursuant to IRC section 613A(d)(1) shall be carried over to succeeding years and treated as an amount allowable as a deduction pursuant to IRC section 613A(c) for such succeeding year, subject to the 65 percent limitation of IRC section 613A(d)(1). For purposes of adjustment to basis and determining whether cost depletion exceeds percentage depletion with respect to the production from a property, any amount disallowed as a deduction under IRC section 613A(d)(1) shall be allocated to the respective properties in proportion to the percentage depletion otherwise allowable to such properties under IRC section 613A(c). After allocation of the amounts disallowed, another comparison of cost depletion and percentage depletion will be made to allow whichever is greater. The amounts disallowed will be carried over to subsequent years. See Exhibit *4.41.1-7*for example.

4.41.1.3.7.4 (10-01-2005)
Lease Bonus

1. Bonus is the term applied to the considerations received by the lessor upon the granting or execution of an oil and gas lease or sublease. It may be paid in a lump sum or in installments.

2. To the payor (lessee), the bonus payment is a capital investment made for the acquisition of an economic interest in the minerals (working interest). A production payment retained by the lessor is treated as a bonus payable in installments. See Treas. Reg. 1.636–2(a). The lessee's investment in the working interest is recoverable through deductions for depletion (if the lease becomes productive), abandonment loss (if the working interest becomes worthless or expires), or as cost of sale (if the working interest is sold).

3. To the payee (lessor), the bonus payment is ordinary income subject to cost depletion. See Treas. Reg. 1.612–3(a). Percentage depletion is not allowed on lease bonus payments. See IRC section 613A(d)(5).

4. As explained in IRM 4.41.1.3.7.2, the cost depletion formula in Treas. Reg. 1.612–3(a) does not produce a realistic result with respect to a nonproven property. However, in *Collums V United States* , 480F. Supp. 864, 51, the Court allowed a sublessor to use the computation to deduct 100 percent of his basis in a nonproven property as cost depletion. No action or decision has been issued with respect to this case. The case should not be followed unless it becomes apparent that the result in Collums will be accepted by the Service. Such is not the case at this time. See PLR 8532011.

4.41.1.3.7.4.1 (07-31-2002)
Depletion Restoration

1. If an oil and gas lease on which a bonus has been paid (and depletion was claimed by the lessor) expires or terminates without production, the lessor must restore the depletion claimed to income. See Treas. Reg. 1.612–3(a)(2). However, if a taxpayer has disposed of his/her mineral property subsequent to the receipt of a lease bonus for granting of a lease and prior to the expiration of the lease, he/she is not required to restore to income the depletion previously taken on the bonus. See Rev. Rul. 60–336, 1960–2 C.B. 195.

2. If a taxpayer reports an oil and gas lease bonus with respect to a tract of land, the agent should check prior leases on the tract. It may be that depletion taken on a prior lease, which expired in the current year, should be restored to income.

3. An agent may locate currently expired leases by comparing delay rental receipts from year to year on the books of the taxpayer. Any

discontinued delay rentals indicate either a terminated lease and possible restoration of depletion on the bonus or a nonproducing lease that became productive.

4. On occasion, a lessee may wish to extend an oil and gas lease past its original termination date. This may be done by agreement to extend the lease for a stated period of time, or by the execution of a new lease to take effect immediately on expiration of the old lease. The extension of the old lease or execution of the new lease is commonly called a "top lease. " Under these conditions, the Service's position is that the old lease has not terminated. The lessor is not required to restore the depletion taken on the old lease, and the lessee is not allowed to claim an abandonment loss of his/her cost in the old lease. This is true whether the old lease has been "top leased" in whole or in part. If there is a time lapse between the expiration of the old lease and the beginning of the new lease, then there is no "top lease" assuming the delay is arm's-length. For Top Leases, *See IRM 4.41.1.2.2.3.4.*

4.41.1.3.7.5 (10-01-2005)
Partners and Beneficiaries Depletion Deduction

1. Oil and gas properties are frequently owned by a partnership, trust, or estate. The depletion deduction, allowed by IRC sections 613 and 613A, on oil and gas production is subject to special rules when mineral properties are held by a partnership, trust, or estate. The examiner must be aware of the special rules to ensure that beneficiaries and partners are not allowed to benefit by circumventing the limitations in the law.

2. The partnership is a favorite vehicle for conducting oil operations because of the practice and need to share the inherent risk of drilling for and producing oil and gas. Also, the partnership form is utilized widely to finance oil and gas operations that may be far too costly for one individual or company. However, IRC section 703(a)(2)(F) states that the depletion deduction is not allowed at the partnership level. Depletion must be computed at the individual partner's level and is subject to the special limitations in IRC section 613A. Cost depletion and/or percentage depletion will be allowable under IRC sections 611, 612, 613, and 613A as stated above but only at the partner's level. Preparers sometimes deduct depletion on Form 1065 (*Partnership Income Tax Return*) because some or all of the partners are limited under IRC section 613A, which would deny or limit the allowance of depletion to the partners. By deducting the depletion on the partnership return, it would merely decrease the net income distributed by the partnership, thus, circumventing the limitations under IRC section 613A.

3. Each partner must keep track of his/her adjusted basis in the partnership oil and gas properties to enable him/her to compute cost depletion and tax preference depletion. The partner's basis on the partnership books will usually be reduced by his/her allocable share of depletion although the partner may have been limited under IRC section 613A and be unable to deduct depletion. Therefore, it is likely that the partner's actual basis in the partnership will differ from the basis shown on Form 1065 because of the depletion deduction and other reasons. Copies of the Schedules K, prepared for the members of a partnership, should be inspected to ensure that the depletion deduction has not been deducted at the partnership level and also allocated to certain partners to create a double deduction. In the case of limited partnerships, the partnership may borrow funds from a lending institution for the purpose of exploring or developing mineral property. Any increase in a partner's share of partnership liabilities is treated as a contribution of money that increases basis in his partnership interest. See IRC sections 752(a) and 722.

4. Trusts and estates are also subject to special rules in computing depletion. The administrator or trustee should make the initial election on the Form 1041 (*Fiduciary Income Tax Return*) as to whether cost or percentage depletion is claimed. The law was changed with the 1975 Tax Reform Act. Prior law will not be discussed here because of limited application. Percentage depletion for a trust or estate is subject to the limitations in IRC section 613A.

5. If the administrator or trustee allocates net income to the beneficiaries, they will be considered to have received their pro-rata share of the depletion. The depletion would again be subject to the limitations of IRC section 613A(c) and (d) at the beneficiaries level. Treas. Reg. 1.613A–3(f) explains the distribution of oil income and depletion out of a trust. The beneficiary is entitled to claim cost depletion, in any event, if cost exceeds his/her share of percentage depletion.

6. Examiners should examine or carefully inspect the Form 1041 to ensure that distributions to the beneficiaries is correct and correspond with the amounts reflected on the beneficiaries' returns. It is common practice for a trust instrument to provide for a reserve for depletion. Frequently, in such cases you will find that a trust or estate has claimed depletion upon 100 percent of the oil and gas produced and that the beneficiary has also claimed depletion upon his/her share of oil or gas income. The double deduction of depletion should, of course, be corrected. Refer to Treas. Reg. 1.613A–3(f) for guidance.

4.41.1.3.7.6 (07-31-2002)
Valuations of Oil and Gas Producing Properties

1. Frequently, it is necessary to determine the fair market value of oil and gas properties. Taxpayers may receive producing oil and gas properties as a result of taxable events such as corporate liquidations, exchanges of properties not qualifying for IRC section 1031 treatment, property received for services under IRC section 83, or in an outright purchase or sale. In each of these events, the consideration received is measured by the fair market value of the property.

2. For income tax purposes, the basis of property in the hands of a person acquiring the property from a decedent generally is the property's fair market value at date of death or "alternate date" under IRC section 2032, if elected. See IRC section 1014.

3. Fair market value determinations must also be made in respect to charitable contributions of property under IRC section 170(a).

4. The courts have considered the definition of fair market value many times. The Supreme Court in *Montrose Cemetary Co. v. Commissioner* , 309 U.S. 622 (1940); 23 AFTR 1071; 40–1 USTC 157, stated, "the fair market value is a price at which a willing seller and a willing buyer will trade, both having a reasonable knowledge of the facts ..." Treas. Reg. 1.170–1(c)(a) and 20.2031–1(b) define fair market value as ". . . the price at which the property would change hands between a willing buyer and a willing seller, neither being under any compulsion to buy or sell and both having reasonable knowledge of the facts." A similar definition of fair market value is found in Treas. Reg. 1.611–1(d)(2).

5. Treas. Reg. 1.611–2(d) provides for the priorities of methods to be used in determining the fair market value of mineral property. Treas. Reg. 1.611–2(d)(2) provides that an analytical appraisal (present value method) will not be used in either one of the following situations:

   A. If the value of a property can be determined based on cost or comparative values and replacement value of equipment

   B. If the fair market value can reasonably be determined by any other method. Also see *Green v. United States* , 460 F.2d 412 (5th Cir. 1972); 29 AFTR 2d 72–1138; 72–1 USTC 84,494.

6. Treas. Reg. 1.611–2(e)(4) provides "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 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 of the improvements and of capital additions, if any, necessary to realize the profits." In practice, this method requires that:

   A. The appraiser project income, expense, and net income on an annual basis

   B. Each year's net income is discounted for interest at the "going rate" to determine the present worth of the future income on an annual and total basis

The total present worth of future income is then discounted further, a percentage based on market conditions, to determine the fair market value. The costs of any expected additional equipment necessary to realize the profits are included in the annual expense, and the proceeds of any expected salvaged of equipment is included in the appropriate annual income.

7. A valuation of an oil and/or gas property is an engineering issue and, if the tax consequences warrant, should be referred for engineering services.

8. The agent should obtain, if possible, the data indicated in Treas. Reg. 1.611–2(g).

4.41.1.3.7.7 (07-31-2002)
Gas Injected for Pressure Maintenance

1. The physical characteristics of hydrocarbons and the reservoirs in which they are found are such that, other factors being equal, the higher the pressure in the reservoir the greater will be the ultimate recovery of hydrocarbons. This is true in the first month of production through the last month of production. Ultimate recovery is not necessarily directly proportionate to pressures. However, for every reservoir which produces oil and gas, there is a critical pressure called the "bubble point." The bubble point, sometimes called saturation pressure, is the pressure at which gas in solution with the oil is released and becomes "free gas." When the pressure in the reservoir drops below the bubble point, the gas automatically becomes free and moves more freely through the reservoir. This allows the gas to bypass the oil and leaves it dead in the reservoir. When this happens, much more of the oil clings to the reservoir rock with consequent loss of possible oil recovery. Because of this, good operators use every reasonable means to maintain relatively high pressure in the reservoir throughout its productive life.

2. One method used by operators to maintain reservoir pressures at optimum levels is by the injection of gas. Dry gas can be injected in the gas cap or as "dispersed gas injection." The dry gas injected in the gas cap in the past has served a dual purpose. It provided a place of storage for gas for which there was no profitable market, and it retarded the decline in reservoir pressure. Dispersed gas injection maintains pressure in the reservoir and pushes additional oil to the producing well bores.

3. Another method of tertiary recovery of oil is known as "enriched gas drive" or "miscible displacement." Under this method, a "slug" of liquefied petroleum gas is injected in the reservoir. This is followed by injection of gas or water. The desired effect is that the liquefied gas is miscible with the oil, will wash it from the rocks, and push it to the producing well bores.

4. The tax treatment of injected gas has been the subject of Rev. Ruls. 68–665, 1968–2 C.B. 280, 70–354, 1970–2 C.B. 50; and 73–469, 1973–2 C.B. 84.

5. Rev. Rul. 68–665, 1968–2 C.B. 280, allows depletion on produced dry gas used to fire boilers in a gasoline absorption plant, but the dry gas reinjected into the producing formation is not sold, does not contribute any value to the products sold, and is not subject to an allowance for depletion.

6. Rev. Rul. 70–354, 1970–2 C.B. 50, holds that, where a taxpayer can show that a portion of the injected gas cannot be expected to be recovered with subsequent production, the costs of the unrecoverable portion are deductible under IRC section 165(a) in the year of injection (or in the subsequent year in which it can be shown that such loss has been sustained). " Economic losses" are not allowable. Costs not recoverable under IRC section 165(a) are not deductible under IRC section 162 but are offset against the proceeds of the purchased gas when it is produced and sold in subsequent producing activities. When purchased and injected gas is subsequently produced and sold, the gain (or loss) is ordinary and not subject to depletion.

7. Rev. Rul. 73–469, 1973–2 C.B. 84, prospectively revokes a portion of Rev. Rul. 70–354, 1970–2 C.B. 50, with respect to that portion of the injected gas that will not be recovered. Subsequent to November 5,1973, costs of injected gas which will not be recovered but will benefit the reservoir by its presence in the reservoir over the life of the project, are capital expenditures. These costs are recoverable through depreciation.

8. The agent should be alert when examining lease operating expenses for evidence of expense deductions resulting from purchased gas. Actual deduction may not be listed under gas injected. It could be found under salt water disposal or other similar names. Any account which totals an unusually high amount should be carefully checked against original invoices on a month-by-month basis. The agent could discuss with the production people any gas injection programs. Ask about the cost of injected gas. Ask about earlier gas injection programs. It may be that gas purchased and expensed in earlier years is currently being produced, sold, and percentage depletion claimed on the proceeds. If the property is being produced under some form of unitization agreement, this agreement may contain definite provisions for differentiating between produced previously injected gas and native gas for royalty computation purposes. If a substantial problem arises, engineering services should be requested. The engineer may have special detailed knowledge of the project.

4.41.1.3.7.8 (01-01-2005)
Depletion for Geothermal Deposits

1. Percentage depletion is allowed without restriction for production from a domestic geothermal deposit. The statutory rate is 15%. The restrictions of section 613A, except for the denial of percentage depletion on lease bonuses, do not apply. See IRC section 613(e).

2. A geothermal deposit means a geothermal reservoir consisting of natural heat which is stored in rocks or in an aqueous liquid or vapor (whether or not under pressure).

3. Gross income is to be computed in the same manner as for oil and gas wells. See Rev. Rul. 85-10, 1985-1 CB 180. Technical Advice Memorandum 200308001 addressed a situation where it was impossible to determine a representative market or field price.

4.41.1.4 (01-01-2002)
Sales, Exchanges, and Other Dispositions

1. This section provides the guidelines for dealing with sales, exchanges, and other dispositions of oil and gas interests.

2. Frequently, oil and gas interests are transferred to other owners by assignment. The agent will find the major problem to be in the classification of the transaction as a sale, lease, or sublease. The disposition of worthless leases and abandonments will also be covered in this section since they may involve assignments.

3. This section deals with the disposition of an interest, in whole or part, by sale, assignment, worthlessness, or abandonment. The gain or loss resulting from these dispositions will either be deferred by nontaxable exchanges or taxable. Taxable dispositions can be capital gains or losses or ordinary income. The disposition of an interest may trigger IDC and depletion recapture provisions of the Code. In such cases, there may be a problem with classification of the transaction as a sale, lease, or sublease. Proper classification of an assignment is essential to the correct application of the tax laws.

4. The variety of contract assignments and interests created, transferred, and retained requires a careful reading of the legal documents as a standard examination procedure. A careful interpretation of the contract must be followed by a careful review of the accounting procedures used to record transactions. It should be remembered that the terms of a contract, rather than the intent of the parties, are generally controlling. However, the form of a transaction should not be allowed to take precedence over the real substance of a transaction.

5. When a lease owner transfers an oil or gas lease to another and receives cash or cash equivalent as consideration, such consideration is either a lease bonus, a sublease bonus, or proceeds from a sale. Therefore, it is important that examiners have a good knowledge of the difference between a leasing (or subleasing) transaction and a sale. If the transferor retains a nonoperating, continuing interest in the property, then the transaction is a lease or sublease and the cash (or equivalent) received is a bonus. All other such transactions are sales. *See IRM 4.41.1.4.2*for a discussion of sublease.

   A. When a lease owner retains a nonoperating interest (royalty, net profits) that entitles the holder to a specified fraction of the total production from the transferred property for the entire economic life of such property, the lease owner has retained a nonoperating, continuing interest in the property.

   B. A nonoperating interest is an economic interest which does not meet the definition of operating interest as defined in Treas. Reg. 1.614–2(b). A royalty, overriding royalty or net profits interest is a nonoperating interest.

4.41.1.4.1 (10-01-2005)
Sale or Lease

1. The transfer of oil and gas properties may constitute a lease, a sublease, or a sale. The importance of determining whether there is a sale or lease is that the character of the transaction determines the classification of the income to be reported.

2. If the transfer constitutes a lease, the income received by the lessor is to be reported as ordinary income subject to depletion. If the transaction is a sale, the income may be treated as either ordinary income or capital gain. The agent should be aware that, if a lease is sold and the lease is an inventory item, the proceeds from the sale will be ordinary income. All other income will be either ordinary income, capital gain, IRC section 1254, or IRC section 1231 gain, depending upon the character of the transaction, the holding period, and whether the recapture of IDC and depletion is required.

3. An interest in oil and gas in place is an interest in " real property" for federal income tax purposes (Rev. Rul. 68–226, 1968–1 C.B. 362). This ruling applies in all cases, regardless of how the oil and gas lessee's interest is treated under state law. An oil and gas lease is subject to IRC section 1231 treatment when it is sold; however, such may not be the case when a lease is merely granted or assigned.

4. When a landowner grants a lease reserving a royalty and receives a cash consideration, the transaction is considered a lease arrangement and not a sale (Rev. Rul. 69–352, 1969–1 C.B. 34).

5. Once the transaction has been determined to be a sale, the agent must determine whether the property is producing or nonproducing. The sale of nonproducing property will usually result in capital gain treatment. The sale of producing property may result in a combination of ordinary income, capital gain, and IRC section 1231 gain. As previously stated, mineral leases (developed or undeveloped) are usually real property used in a trade or business. Related lease buildings, equipment, and expenses deducted for tertiary injectants are subject to the recapture provisions of IRC sections 1245 and 1250. IRC section 1254 may require the recapture of IDC and depletion as ordinary income. Therefore, except for the recapture provisions, the gain from the sale or exchange of an oil and gas property is treated as capital gain in accordance with IRC section 1231. Losses are treated usually as ordinary losses under IRC section 1231.

6. A sale of an interest in oil and gas properties may involve the whole property interest or only a part. Examples of fractional sales are as follows:

   A. An owner may assign an entire interest or a fractional interest.

   B. The owner of a working interest may " carve out" of the working interest and assign any type of continuing nonoperating interest in the property and retain the working interest.

   C. An owner of a continuing property interest may assign that interest and retain a noncontinuing interest in production.

7. Most leases are transferred by either sale, sublease or assignment. However, occasionally there may be a nontaxable exchange. Exchanges of property of like kind held for investment, or for use in a trade or business, may be nontaxable. However, if boot or other consideration is received on the exchange of such properties, the gain is taxable to the extent of the boot received [IRC section 1031 and Treas. Reg. 1.1031 (a), (b), and (c)].

8. When a sale of an entire interest in a lease is for cash, the characterization of gain or loss from the sale are simple, as previously discussed in paragraph (2). However, when a fractional interest is sold for cash or for consideration other than cash, a problem may develop in allocating the cash or fair market value of the other consideration between the leasehold and equipment, etc. Since these allocations must be made based on fair market values, they should be made by a petroleum engineer.

9. If a taxpayer assigns a working interest together with the related lease equipment to another and receives no cash consideration but retains a nonoperating interest (overriding royalty or net profits interest), no deductible loss is allowable. The remaining basis in leasehold and equipment becomes the basis in the interest retained. See Rev. Rul. 70–594, 1970–2 C.B. 301 and GCM 23623 C.B. 1943, 313.

10. The examination techniques used in determining whether a transfer of an oil and gas lease has occurred are the same as in any other industry. One procedure is to look at the balance sheet to determine if leases have been transferred, sold, or abandoned. Once you have determined that a transfer has occurred, look at Schedule D to see if any capital gains have been reported. If the sale cannot be verified, questions are in order. It may be appropriate to ask for a list of the oil and gas properties that have been transferred.

11. The main examination problem with a lease transfer is determining whether the transfer is a sale or a lease. Obtain a copy of the sale agreement and determine whether the transaction should be classified as a sale, lease, or sublease. Once the transaction is properly classified, the agent can easily apply the correct tax treatment to the transaction.

4.41.1.4.1.1 (10-01-2005)
Sale of Leasehold After Development

1. When a lease is sold or exchanged, a gain or loss is realized based on the difference between the selling price and the adjusted basis of the property sold.

2. The adjusted basis of the leasehold is determined by taking the original cost of the property, increasing it for capital additions, and reducing it by depletion allowed or allowable. Any writeoffs for abandonments, transfers, partial sales, etc., will also decrease the adjusted basis.

3. Additions to the basis should include costs such as bonuses paid for the lease, attorney fees, and other expenses incurred in connection with the acquisition, expenditures for geological opinions, surveys, geophysical work, and maps in connection with the acquisition or development of a lease. However, geophysical work conducted for a single well location is IDC. The taxpayer may also elect to capitalize intangible drilling and development costs, although capitalization is very rare.

4. The basis of the leasehold is reduced by any cost or percentage depletion allowed or allowable. The basis of depreciable equipment is reduced by any depreciation allowed or allowable. In both cases, any abandonment losses deducted, etc., would reduce the adjusted basis. However, partial abandonment losses are not allowable deductions. Depletion will often exceed the basis in a lease; however, the basis should not be reduced below zero.

5. The Regulations state that, if any grant of an economic interest in a mineral deposit with respect to which a bonus or advance royalty was received expires, terminates, or is abandoned before there has been any income derived from the extraction of minerals, the grantor must restore to income the depletion deduction taken on the bonus or advance royalty. The grantor must also make a corresponding adjustment to his/her basis in the minerals [Treas. Reg. 1.612–3(a) and (b)].

6. Examination techniques found to be helpful in determining correct basis are as follows:

   A. Request the property or leasehold ledger.

   B. Determine if all capital expenditures have been added to the cost basis.

   C. Review abandonments to ensure that the taxpayer is not prematurely writing off the leasehold or that the taxpayer is not claiming a deduction for a partial abandonment of a lease.

7. The following example demonstrates the computation of the adjusted basis for leasehold:

   Initial Cost

   Add:

   - Subsequent additions
   - IDC — if elected to capitalize
   - Attorney fees
   - Geological and geophysical costs — if appropriate
   - Abstract fees
   - Title search costs, etc.

   Less:

   - Abandonment losses deducted
   - Depletion allowed or allowable
   - Basis claimed as a return of capital in reporting a sale of a partial interest
   - Basis attributable to any portion of the property transferred as a gift, or contribution to corporation or partnership, etc.

8. The tax treatment of depletion allowed in excess of the basis of a property sold is explained in by Rev. Rul. 75–451, 1975–2 C.B. 330. Generally, gain on the sale or disposition of property on which percentage depletion has exceeded the basis is limited to the selling price. However, the cost of later capital investments in the property must be reduced by the depletion allowed after the adjusted basis was reduced to zero. The points of the above cited revenue ruling are best illustrated by an example. The taxpayer purchased mineral property for $1,000,000 and sold it several years later for $500,000. Prior to the sale, the taxpayer's allowable depletion amounted to $1,100,000 (this figure includes any cost depletion and percentage depletion taken). The taxpayer's gain would be $500,000. However, if immediately before the sale, the taxpayer invested $300,000 in depletable property, the gain would be $300,000, the sale price of $500,000 minus the basis of $200,000 ($1,000,000 + $300,000 - $1,100,000 = $200,000).

9. Upon the disposition after 1975 of certain natural resource recapture property, taxpayers are required to recapture as ordinary income all or some part of the IDC paid or incurred after 1975. For oil and gas properties placed in service before 1987, partial recapture of post-1975 IDC is required. For oil and gas properties placed in service after 1986 taxpayers are required to recapture all IDC previously deducted, and depletion deductions that reduced the adjusted basis of the property.

10. IRC section 1254 requires that gain is treated as ordinary income in an amount equal to the lesser of "IRC section 1254 costs" or the gain realized on the sale or other disposition. The gain realized in the case of a sale, exchange, or involuntary conversion is the excess of the sales price of the property over the adjusted basis. The gain realized on any other disposition is the excess of the fair market value of the property over it's adjusted basis. For this purpose, the adjusted basis shall not be less than zero. Agents should verify this item in most examinations because it is a frequent source of adjustments. Taxpayers should maintain a capital account and a reserve for depletion account for each oil and gas property. All capital investments should be entered in the capital account when the investments are made. All depletion allowed or allowable for income tax should be entered in the reserve account when appropriate. No adjustment is required to either account merely because the reserve account exceeds the capital account. Appropriate adjustments should be made to each account on the disposition of a portion of the property.

    A. For oil and gas property placed in service before 1987, the amount to be recaptured is the amount deducted as IDC after December 31, 1975, reduced by the amount (if any) by which the deduction for depletion under IRC section 611 (computed either as provided in IRC section 612 or IRC section 613A) with respect to the interest that would have been increased if the IDC incurred after 1975 had been charged to capital account rather than deducted. The amount recaptured is limited to: 1) the amount realized, or the fair market value over the adjusted basis of the property, or 2) the IDC as adjusted above, whichever is the smaller amount.

    B. For oil and gas property placed in service after 1986, the amount required to be recaptured is the smaller of the aggregate amount deducted as IDC on the property plus the depletion deductions that reduced the basis of the property or the gain realized on the disposition. No reduction in the amount of IDC required to be recaptured is allowed for the amount by which the depletion deduction would have been increased if the IDC had been capitalized rather than deducted.

11. Certain dispositions are excluded from recapture. For example, gifts, transfers at death, and transfers in certain tax-free reorganizations. Like-kind exchanges, and involuntary conversions are excluded from recapture only to the extent the property acquired is natural resource property. A lease or sublease is not a disposition. See Treas. Reg. 1.1254–2 for exceptions and limitations.

12. The sale of a portion of a property or an undivided interest in a property requires the allocation of IDC and depletion — consult IRC section 1254(a)(2) and Proposed Treas. Reg. 1.1254–1(b) for dispositions of a portion of a property.

4.41.1.4.1.2 (07-31-2002)
Sale of Lease Equipment

1. Oil and gas lease equipment is sometimes sold. The sale is subject to the rules under IRC sections 1231 and 1245. If the holding period requirement has been met, a taxpayer is entitled to IRC section 1231 treatment subject to the recapture of depreciation under IRC section 1245.

2. Frequently, an entire oil lease will be sold. When this occurs, the sales price must be allocated properly between the lease and the equipment. Usually, the sales contract will specify the sale price of the assets. However, when this is not the case, the sale price should be allocated to the leasehold and the equipment based upon the relative fair market value of each. A petroleum engineer should be requested to make an appraisal of the leasehold and equipment if substantial amounts are involved. See IRM *4.41.1.2.2.4.2* for a full discussion of the allocation techniques.

3. One problem frequently encountered when depreciable assets are removed from the equipment warehouse and sold is that the taxpayer's

book basis may not indicate the correct tax basis. This is due to the customary practice of valuing equipment removed from a lease based upon its condition. This is done in order to pay other owners for their percentage interest. Customarily, the equipment will be placed in the warehouse at the appraised value instead of the adjusted basis. For example, equipment may be valued at 75 percent of the replacement cost if it is in good condition and can be used without additional cost or repairs. The joint owners are paid their share of 75 percent of the new price. Of course, the agent should use the original adjusted basis plus the amount paid to the joint owners as the correct basis for purposes of a sale. See IRM *4.41.1.3.4.1* for discussion of the treatment of equipment transfers under Joint Operating Agreements.

4. The agent should examine closely the sales instruments when both the leasehold and equipment are sold to determine if the correct allocation is made between the leasehold and equipment. If the taxpayer does not allocate any of the sales price (1) or underallocates (1) to the equipment, the amount of section 1245 gain will be distorted. The agent may obtain an inventory of the equipment sold from the purchaser to use in the verification of the sale price and the basis of the assets sold. The sale of a lease and the related equipment for a lump sum is a potential whipsaw case. In cases in which substantial amounts of money are involved, the agent should make every reasonable effort to obtain consistency of treatment by buyer and seller. The seller's sales price of equipment should be the same as the amount capitalized to equipment by the buyer.

5. See IRM *4.41.1.2.2.4.2* for further discussion with emphasis on the buyer.

4.41.1.4.1.3 (07-31-2002)
Allocation Between Leasehold and Equipment

1. The distinction between depletable and depreciable costs is of major importance when a lease is sold. Each of the seller and buyer will normally attempt to allocate the proceeds in a manner which will produce the most favorable tax advantage for himself or herself.

2. When a sale of the lease results in a gain, the seller may attempt to assign as much of the selling price to the leasehold as possible. IRC section 1231 treatment will result from the sale of the leasehold, except for the recapture of IDC and depletion under IRC section 1254. A smaller allocation of the selling price to the equipment sold will result in a smaller recapture of depreciation as ordinary income under IRC section 1245.

3. The purchaser, on the other hand, may attempt to allocate most of the purchase price to depreciable assets, thereby assuring a relatively large depreciation deduction in the future. This is especially tempting when percentage depletion is available.

4. The buyer and seller may attempt different allocations when the equipment is of high value compared to the lease. This situation may result when a lease and equipment are purchased at or near salvage value. The purchaser will allocate substantially all the purchase price to the leasehold. He/she will then claim cost depletion over a relatively short period of time. The gain from the sale of the salvaged equipment, at substantially more than the allocated original cost, will be treated as IRC section 1231 gain and not IRC section 1245 gain. One of the methods used in computing the correct allocation between leasehold and equipment is indicated in Rev. Rul. 69–539, 1969–2 C.B. 141. The price paid for a going mining business was allocated to each asset or group of assets acquired. This included the mineral lease or mineral property. The purchase price was allocated in the proportion of the fair market value of each asset to the fair market value of all the assets acquired.

5. In a nontaxable IRC section 351 exchange, the transferee must use the prior owner's basis for depreciation and depletion rather than the actual purchase price and fair market value of the depreciable and depletable assets received. (*Carter Foundation Production Co. v. Campbell* , 322 F.2d 827 (5th Cir. 1963); 12 AFTR 2d 5659; 63–2 USTC 89,836.)

4.41.1.4.1.4 (10-01-2005)
Sale of Fractional Interests in Oil and Gas Leases

1. A lease can be sold either in whole or fractional shares. Fractional interests are normally made up of two types: working interests and royalty interests. The sale of a fractional part of a working interest normally will result in a IRC section 1231 gain or loss.

2. The lessee who owns the working interest may assign the property to another and retain an overriding royalty. This transaction would be treated as a sublease, not a sale.

3. The original lessee may sell one or more portions of the working interest. There can be many different owners of a working interest.

   Example:

   The original lessee *Taxpayer A* has a 7/8 working interest and sells 1/2 of his 7/8 working interest to *Taxpayer B*. *Taxpayer B* in turn sells 1/4 of the 1/2 of 7/8 working interest to *Taxpayer C*. As a result of the sale, *Taxpayer A* owns $^1/_2$ of 7/8 or .4375, *Taxpayer B* owns 3/8 of 7/8 or .3281 and *Taxpayer C* owns 1/8 of 7/8 or .1094. *Taxpayer A* has 1/2 of the expenses and .4375 of the income; *Taxpayer B* has 3/8 of the expenses and .328125 of the income; and *Taxpayer C* has 1/8 of the expenses and .109375 of the income.

4. If the lessee sells 1/2 of the working interest for a gain, the lessee will report the gain under IRC section 1231.

   Example:

   Taxpayer B leased from *Taxpayer A*. *Taxpayer A* retained a 1/8 royalty interest and received a cash bonus of $20,000, from *Taxpayer B*. *Taxpayer B* in turn sold 1/2 of the 7/8 working interest to *Taxpayer C* for $11,500.

   As a result, *Taxpayer B* would have a capital gain of $1,500 ($11,500 less 1/2 of $20,000). All expenses of production would be shared equally by *Taxpayer B* and *Taxpayer C*, and *Taxpayer A* (the first owner), would report the $20,000 bonus as ordinary income. Any income received by *Taxpayer A* from the 1/8 royalty would be ordinary income subject to depletion under IRC sections 612, 613 and 613A.

5. If an operator agrees to drill an oil and gas well on a leased tract of land and receives from the lessee, in consideration for drilling, an assignment of the entire working interest in the drill site and an undivided fraction of the working interest in another tract of land, two different transactions have occurred.

   A. In the transfer of the entire working interest in the drill site, neither party will realize income since the pooling of capital concept will apply. See Rev. Rul. 77–176,1977–1 C.B. 77. and *Palmer v. Bender* , 287 U.S. 551 (1933).

   B. However, the undivided fraction of the working interest in the remaining tract of land is considered to be compensation to the operator for undertaking the development project on the drill site. The fair market value of the working interest outside of the drill site is included in the gross income of the operator in the earlier of the year the well was completed or when the working interest was received by the operator. The original lessee is considered to have sold the undivided fractional interest for the fair market value on the date of transfer. The nature of the gain or loss will be covered by IRC section 1231. See Rev. Rul. 77–176,1977–1 C.B. 77.

6. If a royalty interest in oil and gas is used by the owner in his/her trade or business, it is not a capital asset. However, it will be subject to provisions of IRC section 1231 if held for more than one year.

   A. If the royalty is held for investment by a nonoperator, gain or loss on a sale will be capital gain or loss.

B. If the royalty is held for sale in the ordinary course of business by a dealer or broker, gain or loss on its sale is ordinary gain or loss (Rev. Rul. 73–428, 1973–2 C.B. 303).

7. A separate property is formed when two or more property owners contribute their separate properties to form one combined operating "unit. " In return for the transfer of property rights, the owners receive an undivided interest in the "unit." Such a transfer generally is considered to be an exchange. Frequently, cash is received or paid as an equalization payment in a unitization. Generally, the cash received will be treated in accordance with the provisions of IRC section 1031.

4.41.1.4.2 (10-01-2005)
Sublease

1. A transaction will be classified as a sublease in any case in which the owner of operating rights, or a working interest, assigns all or a portion of those rights to another person and retains a continuing, non-operating interest in production, such as an overriding royalty. Income received in a sublease is ordinary income.

2. The pivotal point is to determine whether the retained economic interest in the minerals is a non-operating interest such as an overriding royalty.

4.41.1.4.3 (10-01-2005)
Production Payments

1. Treas. Reg. Section 1.636-3(a) defines the term "production payment" . A production payment is a right to minerals in place that entitles its owner to a specified fraction of production for a limited period of time, or until a specific sum of money or a specific number of units of mineral has been received. A production payment must be an economic interest. It may burden more than property. The characteristic that distinguishes the production payment from an overriding royalty is that the production payment is limited in time, or amount, so that its duration is not co-extensive with the producing life of the property from which it is payable. In other words, the life of the production payment is shorter than the life of the burdened mineral property.

2. There are two types of production payments. A retained production payment is created when an owner of an interest in a mineral property assigns the interest and retains a production payment, payable out of future production from the property interest assigned. A carved-out production payment is created when an owner of any interest in a mineral property assigns a production payment to another person but retains the interest in the property from which the production payment is assigned.

3. There are several reasons for the use of production payments.

   A. Production payments are equivalent economically to nonrecourse financing.

   B. Production payments often may be crafted to bridge value perceptions between a buyer and a seller of mineral property.

   C. A seller of property who retains a production payment is permitted to attribute reserves to it for financial statement reporting purposes, thus reducing the reserve reduction suffered by selling producing property.

   D. An owner of a mineral property who carves out a production payment generally retains the tax attributes of the newly burdened mineral property.

4.41.1.4.3.1 (10-01-2005)
Retained Production Payment

1. A production payment that is retained in any transaction except a leasing transaction, occurring on and after August 7, 1969, is treated as a purchase money mortgage and not as an economic interest in the property. Under IRC section 606(c), a production payment that is retained by the lessor in a leasing transaction is treated by the lessee as a bonus payment in installments

2. Under this rule, if a mineral property burdened by a production payment treated as a loan is sold or otherwise disposed of, the seller of a mineral property who retains a production payment will be taxed in the year of sale on the cash consideration received, as well as the outstanding principal balance of the production payment, subject to the installment sales rules. Thus, the seller will immediately realize gain or loss. Compare Treas. Reg. Section 1.636–1(c)(1) with Treas. Reg. Sections 1.1274–2 & 1.1275–4(c)

3. The purchaser of a property that is subject to a retained production payment as described in (1) and (2) above will be taxed on all income accruing to the property as if the production payment did not exist and will be entitled to depletion on such income. See Treas. Regs. 1.636–1 (a)(ii).

4.41.1.4.3.2 (10-01-2005)
Production Payments Pledged for Exploration or Development

1. If an owner of a mineral property (or properties) carves out and sells a production payment and the proceeds from the sale of the production payment are pledged for the exploration or development of the property (or properties), the production payment is not treated as a mortgage loan to the extent that the taxpayer that created the production payment would not realize gross income from the property absent IRC section 636(a). Compare Treas. Reg. 1.636–1(b)(1) with Treas. Regs. 1.1273–2 & §1.1275–4(b). It is also necessary that the proceeds be actually used for exploration and development of the property or properties.

2. Under the conditions cited above, the seller of the production payment is not required to report and pay income tax on the proceeds. The seller of the production payment does not have a basis in the proceeds received. He/she is not allowed a deduction under any section of the IRC for the expenditure of the proceeds. If the money is paid for equipment, the taxpayer has no basis in the equipment purchased. No depreciation is allowable.

3. Because a production payment that is "pledged for exploration or development" is not treated as a mortgage loan, it is treated as an economic interest in the property (or properties) from which it is paid. The owner of the production payment must report as ordinary income, subject to depletion, all payments received from the production payment. The owner of the property (or properties) from which the production payment was carved has no income as a result of production and sale of oil and gas used to pay the production payment.

4. Because the "carved out" production payment is unique, its sale and subsequent payout may not be reported properly by the taxpayer. Discovery, by examination, of improperly reported production payments is extremely difficult. The existence of a production payment sometimes can be found on the division order. However, some production payments may not be recorded and may not appear on the division order. In these instances, the record owner receives the income and distributes it to the beneficial owner. If a taxpayer is receiving income from a production payment and excluding it from taxable income, the income from the production payment may be found in bank deposits or other books and records. Unreported income of a corporation usually will be shown on Schedule M.

5. If a taxpayer has a property on which the income is relatively low compared to operating costs, or the income sharply increases or decreases, it may indicate the existence of a production payment and its creation or termination.

6. Corporations usually will report large production payments in the footnotes to the financial statements.

7. The agent should ask the taxpayer, or representative, if any of the properties are burdened by production payments.

8. If existence of a production payment is discovered and appears material, the agent should study the documents that created the production payment so that he/she may make a proper decision as to its treatment. The agent should then check the taxpayer's treatment to see that it is proper.

9. Since the examination of carved out production payments can be time consuming, the agent should use judgment as to how far this issue should be pursued.

4.41.1.4.3.3 (07-31-2002)
The Ruling Guidelines

1. Rev. Proc. 97-55, 1997-2 C.B. 582 sets forth the conditions under which the Service will entertain the issuance of an advance ruling to the effect that a right to production is a production payment subject to IRC 636.

2. The conditions are:

   A. The right must be an economic interest in mineral in place without regard to IRC section 636;

   B. The right must be limited by a specified dollar amount, a specified quantum of mineral, or a specified period of time;

   C. At the time of creation of the right, it must reasonably be expected that the right will terminate upon the production of not more than 90% of the reserves then known to exist; and

   D. The present value of the production expected to remain after the right terminates must be 5% or more of the present value of the entire burdened property as of the time the right is created.

4.41.1.4.4 (10-01-2005)
Carried Interest

1. The term "carried interest" is normally used to define a type of arrangement arising when one party (the "carrier ") agrees to drill, develop, equip, and operate the working interest owned by another party (the "carried party"). The carrier agrees to pay the carried party's costs of the property and recover his/her costs out of the carried party's share of the oil and gas produced from the property.

2. In *Herndon Drilling Company vs Commissioner* , 6 T.C. 628 (1946), the carried party granted the carrying party a fraction of the working interest together with a production payment payable out of the carried party's retained share of the working interest. The life of the production payment was extended for a period necessary for the recoupment of the carried cost by the carrying party. The court held that the carrying party was taxable on all income from the property until payout. The carrying party, on the other hand, could only deduct IDC to the extent of the working interest owned by the carrying party and had to capitalize the excess. The money received as payment for the production payments was income to the carrying party.

3. In the "Abercrombie" type of carried interest, the carried party assigned a fraction of the working interest and gave a lien on the retained interest to secure development advances made on behalf of the carried party. The carrying party was treated as having made a loan to the carried party to the extent of the carried party's cost of equipment, IDC, and operating expenses (if necessary). The carried party was allowed to treat these costs as if they were paid. As the carrying party recouped these costs from production, the receipts were treated as repayment of loans. This treatment was the result of *Commissioner v. J. S. Abercrombie Co.* ,162 F2d 338, 35 AFTR 1467 (5th Cir. 1947). The Service withdrew its acquiescence (1949-1 C.B. 1) in IRB 1963–1 C.B. 5. The Fifth Circuit specifically overruled its decision in Abercrombie in *U.S. v. Cocke* , 399 F2d 433, 22 AFTR 2d 5267 (5th Cir. 1968), *rev'g* 263 F. Supp. 762, 17 AFTR 2d 888 (DC Tex. 1966).

4. In all of the following revenue rulings, the underlying theory is that the "carrying party" must own the working interest until complete payout to be entitled to deduct all of the IDC. If the carrying party owned 100 percent of the working interest during the payout period, then 100 percent of the IDC may be deducted if a proper election was made.

   A. Rev. Rul. 69–332, 1969–1 C.B. 87, and Rev. Rul. 71–206, 1971–1 C.B. 105, deal with the treatment of IDC incurred by a taxpayer who owns less than a full operating interest in an oil and gas well but who is entitled to receive the entire operating interest income until recoupment of all the taxpayer's expenditures.

   B. Rev. Rul. 70–336, 1970–1 C.B. 145, explains the treatment of IDC by a carrying party whose operating interest is subject to a retained overriding royalty that may be converted to a 50 percent operating interest when cumulated gross production equals a specified amount.

   C. Rev. Rul.71–207, 1971–1 C.B. 160, deals with a situation in which the carrying party who owns the entire operating interest in an oil and gas lease until the carrying party has recouped all of the costs of drilling and completing the well, and thereafter, owns an undivided one-half interest.

   D. Rev. Rul. 75–446,1975–2 C.B. 95, explains the tax treatment of a carrying party who drills and completes an oil and gas well in return for the entire working interest in the lease until 200 percent of the drilling and development plus the equipment and operating costs necessary to produce that amount are recouped, and after such recoupment relinquishes all rights in the interest to the lessee.

5. If some language of the contract omits or allows the exercise of an option to claim a percentage of the working interest before complete payout, the percentage of IDC deductible by the carrying party is affected. The agent should usually schedule and document the changes in the carried interests because they are a frequent source of tax adjustments.

6. In order to know all the facts of a carried interest arrangement, the lease assignments, carried interest agreements, operating agreements, and any letter agreements must be studied. These instruments must be studied because of all of the different types of arrangements and provisions used to suit the needs of the taxpayer.

4.41.1.4.4.1 (07-31-2002)
Sale of a Carried Interest

1. The question that arises is "what will happen if there is a sale of a carried interest?" There are two sides to consider.

   A. The "carried party" who has the right to production to recoup the expenditures of IDC, etc.

   B. The "carried party" person who possesses the lease interest burdened with the carried interest obligation and will not participate in production until payout has been achieved.

payment or the sale of a working interest depending upon the facts.

3. If a taxpayer sells a lease interest that is burdened with a carry, the taxpayer may be entitled to some capital gain treatment, as in the *Frazell* case, where maps were included as part of the property interest (*Frazell v. United States* , 335 F2d 487, 14 AFTR 2d 5378 (5th Cir. 1964); *reh. denied* 339 F2d 885, 14 AFTR 2d 6119 (5th Cir. 1964), *cert. denied*, 380 U.S. 961).

4.41.1.4.5 (07-31-2002) Unitization

1. Unitization occurs when two or more persons owning operating mineral interests agree to have the interests operated on a unitized basis. They further agree to share in production on a stipulated percentage or fractional basis disregarding which lease or interest produces the oil and gas [Treas. Reg. section 1.614–8(b)(6)]. Unitization may either be voluntary or involuntary. Involuntary unitization may be forced by state conservation laws and regulations. There are various reasons why adjoining property owners unitize their property.

   A. Wells can be placed in the most advantageous location, without regard to lease lines, achieving the most economic development and minimizing operation costs.

   B. The operating problems involved in secondary recovery methods, such as water flooding, are more easily answered by converting some wells to injection wells.

   C. Conservation is aided because the development is fitted to the pools of oil or gas rather than the lease lines.

2. The Service's position on unitization follows the exchange theory (i.e. a unitization effects an exchange of taxpayer's interest in a smaller property or properties for an undivided interest in the unit). See Rev. Rul. 68–186, 1968–1 C.B. 354. Under this theory, the formation of a unit falls under the single property provision of IRC section 614(b)(3) and constitutes a tax-free exchange of property under the provisions of IRC section 1031.

   A. IRC section 1031 provides that no gain or loss shall be recognized if property held for productive use in a trade or business is exchanged solely for property of a like kind. Therefore, the exchanges of property interests will be deemed to be exchanges of property of a like kind, even though one property may be developed and the other property undeveloped.

   B. Gain will be recognized only to the extent of any boot received, whether in the form of cash or other property of unlike kind. Loss from such an exchange shall not be recognized. If the property exchanged was held for more than the required holding period, the recognized gain would qualify for capital gain treatment under IRC section 1231. However, the taxpayer could realize ordinary gain if the property exchanged qualifies as IRC section 1245 property.

   C. Loss from such an exchange shall not be recognized.

3. Unitization usually includes not only the mineral interest but also depreciable equipment. Generally, a party to a unitization agreement will have a leasehold cost, which will become the basis for the participating interest in the new unit. If the working interest owner has depreciable equipment, the adjusted basis of the depreciable equipment becomes the basis to his/her interest in the unitized equipment. Boot received upon the unitization exchange is considered to be for a sale of property. Gain must be allocated between the equipment and the leasehold.

4. Legal fees incurred pertaining to the formation of a unit have been held as deductible expenses and not capital expenditures by the Fifth Circuit Court (*Fields v. Commissioner* , 229 F.2d 197 (5th Cir.1956); 48 AFTR 859; 56–1 USTC 54,470).

4.41.1.4.6 (10-01-2005) Exchanges of Property

1. Exchanges of oil property are either taxable or nontaxable depending upon the type of properties exchanged. No gain or loss is recognized when property held for productive use in a trade or business, or for investment, is exchanged solely for property of a like kind, which is also held either for productive use in a trade or business or for investment. The nonrecognition rule applies only if the like kind exchange requirements of IRC section 1031 are met.

   A. If boot is received on the exchange of property, the gain is taxable only to the extent of the boot received. The exchange of a production payment for any type of continuing interest in minerals is held by the Service as a taxable exchange. The Service also holds that a production payment, which is not a continuing interest in a property, is not like kind property when compared with continuing interest in real estate.

   B. Carved out production payments are generally treated as mortgages and will not qualify in a tax free exchange.

2. Examples of exchanges of property of like kind are as follows:

   A. Producing lease for producing lease (*E. C. Laster* , 42 BTA 9420). It was held that the petitioner exchanged three producing leases for four like assets in a nontaxable exchange.

   B. City lot for minerals (*Crichton v. Commissioner* , 122 F.2d 181 (5th Cir. 1941); 27 AFTR 824; 41–2 USTC 808). Mineral rights are interest in real property so minerals for undivided interest in a city lot was a nontaxable exchange.

   C. Ranch land and improvements held for business or investment purposes for working interest (Rev. Rul. 68–331, 1968–1 C.B. 352). "The lessee's interest in a producing oil lease extending until exhaustion of the deposit is an interest in real property. An exchange of such lease for the fee interest in an improved ranch is a 'like kind' exchange, except as to the part of the ranch property consisting of a residence, equipment, and livestock."

3. The following examination techniques may be helpful to examiners in determining if an exchange has occurred:

   A. Ask the taxpayer to identify all material exchanges of property.

   B. Review the depreciation schedules for reductions in different classes of assets.

   C. On corporation returns, look to Schedule M for income not reported for tax. Review the annual reports for exchanges.

   D. Scan the property ledger.

   E. Compare oil lease income from one year to another on a property by property basis, giving attention to large changes. Depletion schedules are useful when comparing gross income.

4. Once you determine an exchange has occurred, ask the taxpayer for the journal entries pertaining to the transaction to determine if any " boot" has been passed. A taxpayer may consider a taxable exchange as a nontaxable exchange and reduce the basis by the boot received.

4.41.1.4.7 (07-31-2002)
Capital Gain Versus Ordinary Income

1. The sale of an entire mineral interest may result in capital gain or ordinary income depending on whether the seller is a dealer or investor.

4.41.1.4.7.1 (07-31-2002)
Dealer

1. Lease brokers are common in oil and gas producing areas. If the property sold is held by a broker for sale in the normal course of the business activity, the taxpayer will be considered a dealer and the income will be ordinary income. IRC section 1231 will apply, however, to the gains from the sale of leases by a dealer or broker if the dealer can establish that the property was held for investment purposes only. Therefore, some taxpayers may be both a dealer and an investor.

2. Rev. Rul. 73–428, 1973–2 C.B. 303, addresses itself to the sale of a royalty interest in oil and gas in place. If the interest is used by the owner in his/her trade or business, it is not a capital asset but will be subject to the provisions of IRC section 1231 if held for the required length of time. If the royalty is held for investment, gain or loss on its sale is a capital gain or loss. If the royalty is held for sale in the normal course of a taxpayer's business, ordinary gain or loss will result.

3. The courts have used various factors in determining whether an individual is a dealer or an investor. Listed below are two cases which highlight these factors.

4. In *Spragins v. United States* , (D. C. Tex. 1978); 42 AFTR. 2d 78–5389; 78–1 USTC 84,323, the court decided that the taxpayer held certain oil and gas leases for investment not for sale in the ordinary course of business. Thus, the taxpayer was entitled to capital gain treatment. The court found that Spragins was, in fact, primarily an oil and gas producer. Spragins did not advertise leases for sale. Most of his gross income came from 31 producing oil and gas properties. He, in fact, drilled seven wells, abandoned six leases, operated several properties, and sold only five properties. The court determined that the properties were not held for sale in ordinary business activity but were held for investment.

5. In *Bunnel v. United States* , (D.C.N.M. 1968); 20 AFTR 2d 5696; 68–1 USTC 86,054, a jury determined that oil and gas leases had been held by the taxpayer primarily for sale to customers in the ordinary course of business. Therefore, gain realized upon the sale of leases was subject to treatment as ordinary income instead of capital gain. No single factor is controlling in determining if the property is held for sale to the customer in the ordinary course of business. Consideration must be given to all the facts. In the above case, the jury was charged to consider the following facts in making their determination:

    A. What was the reason, purpose, and intent of the acquisition and ownership of the oil and gas leases during the period they were owned by the taxpayer?

    B. Was there continuity of sales of oil and gas leases over an extended period of time?

    C. Was the amount of income which the plaintiff received from the sales proportionately large in comparison to other income which they received from other businesses?

    D. Did the taxpayer have sufficient assets to develop the oil and gas lease, either by themselves or together with other people, or were they dependent on selling the property in order to make a gain?

    E. Did the taxpayer hold the various properties for long periods of time?

    F. What was the extent of taxpayer's activities in developing the leases or soliciting customers for sale?

6. The sale of oil properties will usually be reflected on Schedule D. The agent must use his/her judgment in determining whether the taxpayer is a dealer or investor. The guidelines shown in the above cited cases should be followed in determining the correct classification of the taxpayer-dealer or investor. This is a difficult issue that will be decided by the facts in each case. The agent must obtain all of the facts concerning the number of leases sold, the taxpayer's primary business, the extent of advertising, etc., before proposing to treat a taxpayer as a dealer.

4.41.1.4.7.1.1 (07-31-2002)
Investor

1. The producer or casual investor will usually buy royalty interests with the hope that oil or gas production will be obtained. If there is production production or even good prospects of production, an investor may receive an offer to sell. This sale would qualify for capital gain treatment provided the property was held for the required length of time.

2. An investor will sometimes trade a fractional interest in a royalty for an interest in another royalty. This type of transaction follows the rule wherein gain realized is recognized only to the extent of the money or unlike property received.

3. Some techniques to be used in auditing an investor in royalties is to note all credits to the royalty asset accounts and determine their nature. This may reveal a transaction not otherwise shown by a purchase or sale. Accounts in the spouse's name should be examined for items which might represent unreported income. If a loss is shown on the sale of a royalty, determine if there has been any writeoff for abandonments, etc., in prior years. Be alert to those situations where a fractional part of an interest is sold. The cost of the entire interest may be shown as the basis for the part sold. Also, remember that any depletion claimed (percentage or cost) must be applied to reduce the basis. A nonproducing property may be under an existing lease for which the taxpayer received a bonus on which depletion was taken. In the termination of the lease, the depletion on the bonus should be restored to income; however, depletion on the bonus is not required when a property is merely transferred. See Rev. Rul. 60–336, 1960–2 C.B. 195.

4.41.1.4.7.2 (10-01-2005)
Sale of Geological and Geophysical (G & G) Data

1. Geological and Geophysical (G & G) data obtained through exploratory and seismic activities is frequently exchanged and/or sold to other parties interested in the hydrocarbon potential of a given area. Brokers are active in the sales, swaps, and exchanges of this data. Many times the taxpayer will sell geological data after it has been deducted as G & G expense or an abandonment. Care should be used in the verification of any basis claimed on the sale of data.

2. There are a number of companies that gather G & G data, for the purpose of selling it to other parties interested in exploring for oil and gas.

    A. The seismic company acquires G & G data through various means. In some cases, the seismic company will incur all the cost to shoot the seismic and attempt to sell the data to as many interested parties as possible. In other arrangements, the seismic company will organize operators who are interested in certain geographic areas. The seismic data usually is recorded on magnetic tapes.

    B. The Service's position is that the expense to acquire seismic data is a capital expenditure. When the seismic data is inextricably connected to tapes, it is the tapes that are the subject property and various courts have found them to constitute depreciable tangible property. See *Texas Instruments, Inc. v. United States* , 551 F.2d 599 (5th Cir. 1977) and the dissenting opinion in *Sprint Corp. v. Commissioner* , 108 T.C. 384 (T.C., 1997). MACRS Asset Class 13.1 (Drilling of Oil and Gas Wells) is appropriate since it includes assets used in the provision of geophysical services. The enactment of IRC section 167(g) restricted the use of the income forecast method of depreciation, and it is not appropriate for seismic data.

4.41.1.4.8 (10-01-2005)
Worthless Minerals

1. IRC section 165 allows a deduction for losses not compensated for by insurance or otherwise if incurred in a trade or business or any transaction entered into for profit though not connected with the taxpayer's trade or business. The losses must be evidenced by a closed and completed transaction or a fixed, identifiable event that establishes that the property has become worthless. The taxpayer must substantiate two facts:

   A. That some event during the taxable year established the worthlessness of the property.

   B. That no event had occurred in a prior year that had established its worthlessness in a prior year. A formal disposition of the interest in the property is not required if worthlessness can be proven by any other means (Rev. Rul. 54–581, 1954–2 C.B. 112).

2. The closed transaction that most clearly establishes worthlessness of oil and gas properties is the relinquishment of title. This can be accomplished by nonpayment of delay rentals, surrender of leases, or a release recorded with a governmental municipality in the appropriate records.

3. An identifiable event that may prove an oil and gas property worthless is the drilling of a dry hole on or near the property. In each case, it is a question of fact as to whether the dry hole does or does not condemn the property as worthless. Usually, the agent should consult an engineer concerning worthlessness (*Goodwin v. Commissioner* , 9 B.T.A. 1209 (1928); acq., VII–1 C.B. 12).

4. A loss deduction is not allowed for shrinkage in value. In *Louisiana Land and Exploration Co. v. Commissioner* , 7TC 507 (1946) acq. on other issues, 1946 2C.B. 3, aff'd, 161 F.2d 842 (5th Cir. 1947), 35 AFTR 1388, 47–1 USTC 302, the taxpayer purchased a tract of land for $30,000. The main purpose was to purchase the mineral rights, and the taxpayer allocated $15,000 to mineral rights and $15,000 to surface rights. During the year, the taxpayer's lessee drilled a dry hole and forfeited his/her lease. The taxpayer retained the ownership in the surface. The court refused to allow the deduction for worthlessness of minerals. ([In cases where the mineral and surface rights have separate values for estate purposes, the findings may be different.)

5. In *Lyons v. Commissioner* , 10 T.C. 634 (1948), a deduction for partial worthlessness was denied because the taxpayer had several wells on one tract and abandoned some of the wells. The tract was viewed as one unit.

6. IRC section 465 generally provides that the amount of loss otherwise allowable with respect to an activity cannot exceed the aggregate amount which a taxpayer has at risk with respect to such activity at the close of the taxable year. Each separate oil and gas property is treated as a separate activity for the purpose of IRC section 465. See IRC section 465(c)(2)(a)(iv).

4.41.1.4.8.1 (07-31-2002)
Examination Techniques

1. The examiner, in the beginning of the examination, should obtain a list of canceled leases showing project identification, lease identification, cost, and date acquired. Verify the bases of the leases canceled, and determine if any portion of any one of the leases written off is in a unitization project.

2. Determine if the property charged off has been top leased in a subsequent year; and check to see if title to the property is still held by the taxpayer. An easy way is to check delay rentals paid on the leases that have been abandoned.

3. Allowance of a deduction for worthlessness should not be based on the consideration of only one or two factors. A good judgment can be made only when all of the facts are known.

4.41.1.4.9 (07-31-2002)
Abandonment of Lease

1. Lease costs usually are deducted from gross income in the year of abandonment. Usually, the year of abandonment will coincide with the year that the property becomes worthless. However, if the situation arises in which the property becomes worthless prior to the overt act of abandonment, the Service considers the year in which worthlessness is established to be the controlling year. "It is held that an abandonment loss is deductible only in the taxable year in which it is actually sustained. An abandonment loss which was actually sustained in a taxable year prior to the year in which the overt act of abandonment took place is not allowed as a deduction in the later year." See Rev. Rul. 54–581, 1954–2 C.B. 112.

2. The taxpayer may purchase a large amount of acreage in a single property and later attempt to abandon part of the acreage that is undesirable. This type of abandonment is called a partial abandonment. A partial abandonment loss is not allowable, an abandoned loss can be claimed only when the entire property is abandoned.

3. The abandonment of nonproducing property has, in fact, occurred when a delay rental payment is not made by the due date. Usually, the loss will be the cost of the property since there should be no deduction claimed for depletion, partial abandonments, etc.

4. The abandonment of producing properties could be a problem for the examiner. If the property has been producing, the logical question to ask is, "Why does the taxpayer have a loss on abandonment?" Usually, if the reserves have been correctly determined on the property, a taxpayer should have recovered the cost basis by either percentage or cost depletion. Since the taxpayer is entitled to cost depletion, if the lease has run its normal life, the entire cost should have been recovered (*James Petroleum Corp. v. Commissioner* , 24 T.C. 509 1955;aff'd 238 F2d 678 (2d Cir. 1956), cert. den. 353 US 910, acq., 1956–1 C.B. 4). However, a property may become unprofitable before the basis is recovered. The examiner must obtain all of the facts.

5. Expiration under the terms of the lease is considered to be an abandonment if there is no extension of the lease. Under the terms of the lease, the taxpayer may be allowed to operate the lease for a specific time (e.g. 10 years) or may have an option to extend the lease for a specific time. The examiner should scrutinize the terms of the lease. If the lease has no options to extend or if the options have not been exercised, the abandonment should be allowed. In allowing an abandonment due to expiration under the terms of the lease, the agent should be aware of the possibilities of top leasing.

4.41.1.4.9.1 (07-31-2002)
Examination Techniques

1. In auditing abandonment losses, examiners should first look to the abandonments themselves and ask the following questions:

   A. What overt act is evidence of the abandonment? If the taxpayer is claiming an abandonment, there should not be any delay rental deductions in the loss year.

B. Does the lease expire on a certain date?

C. Are there any options to renew?

D. Has the taxpayer canceled the lease, let it expire, or made a new lease on the same property?

E. Is the taxpayer still paying the taxes on the property he/she is abandoning? Has the taxpayer filed a release in the county records?

2. Examiners should be aware of the timing difference between worthlessness and abandonments. However, a practical approach must be used in deciding whether or not to make roll over adjustments.

4.41.1.4.9.2 (07-31-2002)
Forfeit of Lease

1. A forfeit of a lease may occur when the production of the lease falls to the point where it is not profitable to continue the lease. In a productive lease agreement, the terms generally call for forfeiture of the lease 90 days after production stops. In a nonproductive lease, the forfeiture of the lease may occur when the taxpayer fails to pay the delay rental.

2. Examiners should be aware that, in general, delay rentals are not based on a calendar year.

   A. For example, the lease runs July 1 to June 30 of the following year and the taxpayer pays the delay rental for the fiscal year but decides to abandon the lease as of December 31 of the current year. The Service might not allow the deduction until the following year since the delay rental would secure the lease until June 30 of that year.

   B. However, if an event occurred which proved the lease worthless prior to January 1 of the following year, or the taxpayer released the entire lease prior to January 1 , examiners should exercise good judgment in considering the December 31 abandonment loss. Generally, delay rentals are not paid on producing leases. Most leases provide that they will remain in effect as long as the lease is producing.

4.41.1.4.9.3 (07-31-2002)
Top Lease

1. Top leasing occurs when the taxpayer extends the lease prior to the expiration of the original lease. When top leasing occurs, the IRS will not recognize any abandonment losses on the original lease. When the taxpayer extends the original lease, the agent does not have much of a problem since the extension is a continuation of the old lease and readily available upon examination.

2. The main problem in top leasing occurs when the taxpayer extends the lease by obtaining a new and separate lease on the old property. This fact usually is not readily apparent to the agent; and the agent may allow the abandonment under the assumption that the original lease has terminated, when, in reality, it has not. Finding a top lease is difficult. Two methods of determining whether a top lease exist are:

   A. Comparing new leases against the abandoned leases. Because the new lease probably will not refer to the old lease, the agent will have to compare descriptions and locations.

   B. Asking the taxpayer if there were any top leases. The agent should obtain a legal description of the abandoned leases. The agent should then ask the taxpayer's landman for a current map of the pertinent area showing the taxpayer's current holdings. Top leases should be easily identified when comparing the maps and the legal descriptions.

4.41.1.4.10 (07-31-2002)
Sale of Scrap Equipment

1. The gain on sale of scrap equipment such as pipes, pumps, tanks, etc., will depend on what the taxpayer means by the term "scrap equipment. "

2. If the taxpayer defines scrap equipment as a sale of usable equipment that can be used in other oil and gas endeavors, the gain will be considered IRC section 1231 gain on the sale of an asset used in a trade or business—subject to IRC 1245 recapture. If the taxpayer is using an ADR method of depreciation, the agent will need to determine if the gain or loss is normal or abnormal. Abnormal (extraordinary) gains or losses for ADR are subject to the tax treatment of IRC sections 1231 and 1245 recapture. Normal retirements resulting in gains or losses will not be reported as income but will affect the asset reserve.

3. If the taxpayer intends the term "scrap equipment" to mean unidentified equipment and parts not usable in future oil and gas development, sale of scrap equipment is treated as ordinary income.

4.41.1.4.11 (07-31-2002)
Engineering Referrals

1. When an agent encounters an engineering problem and referral to an engineer agent is not mandatory under IRM or local directives issued thereunder, he/she may still request the services of an engineer agent. Discussion with the group manager is appropriate. In many cases, an informal discussion with an engineer can solve the problem. However, when a referral is necessary, a *Form 5202 (Request for Engineering Services)*is used to request the engineer.

2. Some of the issues an agent may encounter in which an engineer's services would be helpful are listed below:

   - Worthlessness
   - Abandonment
   - Valuations of leasehold and equipment
   - Depletion

3. Instructions for mandatory referral of oil and gas issues to engineers vary from Territory to Territory. Agents should follow local guidelines.

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