



Part 4. Examining Process

Chapter 41. Oil and Gas Industry

Section 1. Oil and Gas Handbook

4.41.1 Oil and Gas Handbook

- 4.41.1.1 [Overview of Oil and Gas Handbook](#)
- 4.41.1.2 [Acquisitions](#)

Manual Transmittal

December 03, 2013

Purpose

(1) This transmits revised IRM 4.41.1, Oil and Gas Industry, Oil and Gas Handbook.

Material Changes

- (1) Updated Oil and Gas Industry Overview, *IRM 4.41.1.1.2* including a description of the oil and gas well drilling industry and international issues. Added *Business Segments*, downstream and upstream in *IRM 4.41.1.1.2.1*.
- (2) Removed references to Petroleum Industry Program (PIP) as IRM 4.40.4 is obsolete.
- (3) Updated *Research Material Available in Oil and Gas Taxation* in *Exhibit 4.41.1-1*.
- (4) Updated *Specialist Referral Procedures* in *IRM 4.41.1.1.3*.
- (5) Removed petroleum controlled issues formerly at IRM 4.41.1.1.3.3 in Delegation Orders 4-17 and 4-31 as both were rescinded.
- (6) Added *IRM 4.41.1.2.2.3.1 Capitalization of Non-direct Costs under IRC 263(c) or IRC 263A*; revised *IRM 4.41.1.2.2.3.2 Geological and Geophysical Expenditures (G&G)*; revised *Exhibit 4.41.1-5, Classification of Expenditures in Acquisition, Development, and Operation of Oil and Gas Leases*; and added *Exhibit 4.41.1-6 Rules Regarding Foreign G&G expenditures*.
- (7) Added *IRM 4.41.1.2.4.4* describing distinction between intangible drilling costs (IDC) and nonproductive well costs.
- (8) Added new *IRM 4.41.1.2.4.5* describing plug and abandonment of wells versus temporary abandonment.
- (9) Added new *IRM 4.41.1.2.4.8.5, Cash and Carry Arrangements*.
- (10) Revised *IRM 4.41.1.2.4.9, Offshore Development, Platforms and Drilling Rigs* including new content on Subsea Wells, Deepwater Platforms, and examination issues.
- (11) Updated court citations in *IRM 4.41.1.2.4.9.4, Platform Costs Litigation*.
- (12) Updated *IRM 4.41.1.2.4.9.5, Each Platform Analyzed Separately* for Rev. Rul. 89-56.
- (13) Clarified *IRM 4.41.1.3.1.1, Income to Royalty Owner*.
- (14) Revised *IRM 4.41.1.3.2.4, Depreciation* for unit of production method for wells and added two new sub-sections pertaining to placed-in-service dates for wells and MACRS class life descriptions. Also added new *Exhibit 4.41.1-43* providing MACRS asset classes commonly used by taxpayers in the petroleum industry.
- (15) Added new *IRM 4.41.1.3.2.9, Future Liabilities for Well Plugging, Platform Dismantlement, and Property Restoration*.
- (16) Updated *IRM 4.41.1.3.3.6* providing further guidance on examination of tertiary injectant expenses.
- (17) Updated *IRM 4.41.1.3.4 Enhanced Oil Recovery Tax Credit* to reflect status to issue of strategic value, recently-issued guidance provided through Industry Director Directives and extension of the credit to Alaska gas processing plants.
- (18) Added *IRM 4.41.1.3.5 IRC 45Q Credit for Sequestration of Carbon Dioxide in Enhanced Oil or Natural Gas Project*.
- (19) Added *IRM 4.41.1.3.7 Marginal Well Credit* per IRC 45I.
- (20) Updated *IRM 4.41.1.3.9.2.1, Depletable Basis*.
- (21) Revised *IRM 4.41.1.3.9.2.2, Reserves of Oil and Gas*.
- (22) Revised *IRM 4.41.1.3.9.2.3, Appropriate Additional Reserves of Oil and Gas* and clarifying SEC definitions pertinent to reserves prior to 2010 and post 2009 as *Exhibit 4.41.1-45* and *Exhibit 4.41.1-46*.
- (23) Updated *IRM 4.41.1.3.9.3.10, Depletion Allowable to Independent Producers and Royalty Owners*.
- (24) Revised *IRM 4.41.1.4.6, Exchanges of Property involving Like Kind Exchanges of Oil-Gas Property*.
- (25) Updated *IRM 4.41.1.4.8, Worthless Minerals* with new case decisions.
- (26) Added new *IRM 4.41.1.4.9, Worthless Securities and Oil and Gas Examinations*.
- (27) Updated income tax provisions for the American Jobs Creation Act of 2004, Energy Policy Act of 2005, Tax Increase Prevention and Reconciliation Act (TIPRA), and the Emergency Economic Stabilization Act to delete reference to IRC 613A. See *Exhibit 4.41.1-27, Exhibit 4.41.1-28, Exhibit 4.41.1-29, and Exhibit 4.41.1-30*. Deleted expired tax provisions previously numbered as Exhibits 4.41.1-27 Working Families Tax Relief Act and 4.41.1-31 Tax Relief and Health Care Act of 2006.

- (28) Updated *IRM 4.41.1.5.2, Partnerships*.
- (29) Added new *IRM 4.41.1.5.2.10* describing audit techniques for disguised sale transactions.
- (30) Added new *IRM 4.41.1.5.3, Publicly Traded Partnerships*
- (31) Updated *IRM 4.41.1.5.4.1, Alternative Minimum Tax Considerations*.
- (32) Added new *IRM 4.41.1.5.4.3, IRC 482 Intercompany Services*.
- (33) Added new *IRM 4.41.1.5.4.4, IRC 199 Domestic Production Deduction*
- (34) Updated *IRM 4.41.1.6, Petroleum Refining*, including updated *IRM 4.41.1.6.3.1, Allocation of Acquisition Costs*, new *IRM 4.41.1.6.1.5 Inventory - LIFO* and *IRM 4.41.1.6.7 Indirect Expenses*.
- (35) Under *IRM 4.41.1.6, Petroleum Refining*, added *IRM 4.41.1.6.4.4, Line Fill Inventory Issue* and new *Exhibit 4.41.1-42, Regulatory Agency Filings for Refiners*; revised *IRM 4.41.1.6.7.3 Refinery Repairs*; updated the diagram of the petroleum refining process in *Exhibit 4.41.1-14*; and added *IRM 4.41.1.6.7.4 Turnarounds*. Several new tax incentives are described in *IRM 4.41.1.6.7.6 Tax Incentives for Refining and Use of Renewable Fuel Incentives: IRC 45H, 179B, 179C, 40A*, including a new *Exhibit 4.41.1-31 History of IRC 40A, Biodiesel and Renewable Diesel Fuel Credit*.
- (36) Under *Petroleum Refining*, added *IRM 4.41.1.6.8.2.2, Depreciation for Joint Operations*, *IRM 4.41.1.6.8.3, Extraordinary and Casualty Losses*, revised *IRM 4.41.1.6.8.3.4, Fines and Penalties* arising from environmental and safety violations. Updated *IRM 4.41.1.6.11, Alaska Pipeline Depreciation Treatment of Natural Gas Property*, and *IRM 4.41.1.6.12, Natural Gas Line Depreciation*. Added *IRM 4.41.1.6.7.1.2, Depreciation for Precious Metal Catalysts*.
- (37) Updated and renamed *IRM 4.41.1.7.1, Overview of Intercompany Marine Transportation*.
- (38) Added new *IRM 4.41.1.8, Leveraged Oil and Gas Drilling Partnerships (LOGDP)*.
- (39) Added new LOGDP Exhibits in *Exhibit 4.41.1-32, Exhibit 4.41.1-33, Exhibit 4.41.1-34, Exhibit 4.41.1-35, Exhibit 4.41.1-36, Exhibit 4.41.1-37, Exhibit 4.41.1-38, Exhibit 4.41.1-39, Exhibit 4.41.1-40, and Exhibit 4.41.1-41*.
- (40) Replaced *IRM 4.41.1.9, Definition of Terms Pertaining to the Oil and Gas Industry* with *Exhibit 4.41.1-44 Glossary of Oil and Gas Industry Terms*.
- (41) Added *IRM 4.41.1.9 Activities and Services Provided on the U.S. Outer Continental Shelf*.
- (42) Renumbered and updated *Exhibit 4.41.1-26, Analysis of SPE Factual Scenarios of Probable Reserves*.
- (43) Added two new exhibits providing SEC definitions pertinent to oil and gas reserves, *Exhibit 4.41.1-45* and *Exhibit 4.41.1-46*.

Effect on Other Documents

IRM 4.41.1 dated January 28, 2011 is superseded.

Audience

Examination functions in all divisions.

Effective Date

(12-03-2013)

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4.41.1.1 (12-03-2013)

Overview of Oil and Gas Handbook

1. This handbook introduces examiners to and assists them in the examination of income tax returns of taxpayers in the oil and gas industry.
2. Diligent use of these guidelines will shorten the time needed to acquire the examination skills essential to this specialty. Nothing contained herein should discourage examiners from improving upon these techniques or from exercising their own initiative and ingenuity.
3. Authoritative industry references are available in *Exhibit 4.41.1-1 Research Materials, Oil and Gas Taxation*. The list is also useful for the study of oil and gas taxation. While the list is not exhaustive, it will provide an excellent introduction.
4. Refer to *Exhibit 4.41.1-10, Items to Consider During Examination* for preparing Forms 4318, 4764, 4764-B and 886-A.

4.41.1.1.1 (12-03-2013)

Contents and Distribution

1. These guidelines are a compilation of the examination techniques used by some of our most experienced revenue agents. They are intended to illustrate the variety of problems encountered in examining Federal income tax returns involving oil and gas transactions.
2. The oil and gas examination guidelines in this handbook identify potential issues and problem areas that an agent will likely encounter in the examination of an oil company or individual operator. While no guideline, examination plan, or textbook can cover all possible issues or examination techniques in an industry as complex and diverse as the petroleum industry, the handbook will be a useful tool for the examiner. However, individual initiative, planning, and research will be needed to cope with the rapid changes taking place within the petroleum industry.
3. This industry, which involves the exploitation of natural resources, is subject to a large number of substantive tax law provisions. The Internal Revenue Code (IRC) and Regulations have many code sections that deal with the extractive industries. It becomes impractical, if not impossible, to clearly delineate examination techniques from the application of law. In many sections of this IRM, examination techniques are interspersed with discussion of the legal aspects of the particular transactions involved.
4. References to the tax law will be general and brief in nature and should not be relied upon for complete understanding of the law. Rather, it is recommended that the agent augment these guidelines with research and study. Included in *Exhibit 4.41.1-1* is a reference guide to aid research and to supply leads to the major tax law areas concerning the oil and gas industry.
5. Many examination features in the oil and gas industry are common to commercial enterprises but the handbook will highlight those areas peculiar to the industry.
6. Note that the examination techniques in this issuance are suggestive but not mandatory procedures for field personnel.
7. These guidelines do not alter existing technical or procedural examination instructions contained in the IRM. In the event of any inconsistencies between these guidelines and the basic text of the IRM, then the latter will prevail. Procedural statements in this issuance are for emphasis and clarity and are not to be taken as authority for administrative action.

8. In summary, a good knowledge of oil and gas tax law can only be acquired through study and several years of examination experience in the industry. The examination techniques and procedures presented here are not intended to serve as a textbook in oil and gas tax law. The material presented here should be studied, considered, and applied where appropriate to ensure an efficient and effective examination. It is unlikely that an examiner would ever apply all of the techniques mentioned here in any one examination.
9. Examiners should consider taking the Micromash course "Oil and Gas Taxation" prior to beginning an examination of an oil and gas company.

4.41.1.1.2 (12-03-2013)

Oil and Gas Industry Overview

1. The oil and gas industry is one of the largest and most important segments of the U.S. economy. Due to the size and complexity of the industry, some basic examination guidelines are needed to assist examiners.
2. The exploration, development, and production of crude oil and natural gas require enormous amounts of capital. To obtain the funds needed, companies sometimes join together and pool their resources to explore for oil. Large integrated oil companies, as well as small companies and individuals, participate in the exploration, development, and production phases of the oil and gas industry. Many times partnerships are formed to enable outside investors to invest in drilling ventures. The investors may have little knowledge of the oil and gas industry. They are willing to invest funds in risky drilling ventures because the tax benefits are favorable, and large economic benefits are possible. Institutional investors that hope to achieve moderate returns without undue risk are known to invest sizeable amounts in the industry by purchasing royalty interests in producing oil and gas properties.
3. The transportation, refining, and marketing of petroleum and natural gas by-products, which also require extremely large capital investments, used to be dominated by large vertically integrated oil companies. However, due to a variety of business, economic and regulatory reasons, the number of companies that own all segments of the industry has been greatly reduced. The industry is as active and dynamic as ever, and the large capital requirements still exist, but the complexion has changed markedly. For example, it is fairly common for publicly traded partnerships to own significant portions of midstream and transportation assets.
4. The importance of the petroleum industry to the economy of the United States has led Congress to pass specialized tax laws that are unique to the oil and gas industry. Petroleum industry accounting records have been adapted to the specialized nature of the industry. As a result, an efficient and effective examination of a return with oil and gas investments, transactions, or operations will require specialized knowledge of the industry, accounting, and tax law.
5. Oil and gas drillers and service companies make up another large part of the industry. The drilling companies are hired on a contract or fee basis for the drilling rig, labor force, and various other expenses related to the drilling of the well. The fee is often charged on a per-day basis and referred to as a "day rate". Service companies are hired by oil and gas exploration companies to provide the technology, tools, and expertise throughout the drilling, evaluation, completion, and production phases of the well. Many drillers and service companies are foreign controlled corporations or domestic corporations owning foreign subsidiaries, so referrals to international examiners are often necessary. Some common areas that examiners should be aware of when working these types of companies are:
 - A. transfer pricing
 - B. research credit
 - C. IRC 199
 - D. foreign tax credit

4.41.1.1.2.1 (12-03-2013)

Business Segments

1. At a high level the oil and gas industry is often viewed as having only two primary segments – "Upstream" and "Downstream". The upstream segment explores for and produces oil and gas that is used by the downstream segment. The downstream segment transports, processes, and refines oil and gas into desirable products and by-products, and then markets them to industrial, wholesale and retail customers. However, it is more appropriate to describe the general activities of these business segments as follows:
 - A. **Upstream:** companies in this segment explore for crude oil and natural gas; develop oil and gas fields; and produce oil and gas via wells. The gathering of those raw products by the producer in the general vicinity of its wells is sometimes considered one of its upstream activities.
 - B. **Downstream:** companies in this segment perform the functions that are not normally considered part of upstream activities. These functions include gathering, processing, transportation, refining, marketing, distribution and retailing. There are some accepted sectors of the downstream segment which are described below, although some functions are performed by more than one. The physical and chemical differences between crude oil and natural gas dictate that the conversion of those raw products into finished ones is typically performed in a different manner (i.e., by different assets, in a different sequence, and in different proximity to the wells).
2. Generally accepted sectors of the downstream segment are:
 - **Midstream and Transportation:** companies in this sector perform functions such as gathering crude oil and natural gas from well and field sites; treating natural gas to remove contaminants and to recover natural gas liquids (NGLs); and operating natural gas plants to separate natural gas into "pipeline quality gas" (essentially methane) and other gas and liquid components. These companies also operate "fractionation plants" where large quantities of NGLs are separated into components such as ethane, propane, butane, and iso-butane. Important transportation functions include moving crude oil from gathering sites to oil refineries. Pipelines are normally used; however railcars are occasionally used to move significant quantities of crude oil while a pipeline is under construction. A very extensive network of intrastate and interstate natural gas pipelines transports gas to local utility companies and industrial customers. Companies in this sector also transport refined liquid products from refineries and NGLs and pipeline quality gas from gas plants. Transportation of large quantities is normally done via pipelines, although railcars and river-going barges are used to move some liquid products. Very large ships known as oil tankers and liquefied natural gas (LNG) carriers transport oil and gas between countries and continents.
 - **Refining:** oil refineries convert crude oil into a wide variety of finished products, such as transportation and heating fuels, lubricants, waxes, asphalts, and petroleum coke. Oil refineries also commonly provide large quantities of hydrocarbon gases and liquids to chemical plants (a.k.a., "petrochemical plants") which convert them into plastics, plastic resins, and other products. Oil refineries that process large quantities of "heavy" crude oil may also produce large quantities of elemental sulfur "powder" or "bricks" which can be transported as solids via rail or barge.
 - **Marketing and Retail:** companies in this sector distribute products like gasoline, diesel, heating oil, and aviation fuel to wholesalers, retailers and end users. While a large percentage of gasoline stations are branded with the name of a well known oil company or refiner, only a minor percentage are actually owned by those corporations. The great majority are franchises. Even with corporate-owned stores, the products they sell may have originated with wells and/or refineries owned by other companies. Over the past few decades the traditional gasoline "service station" has largely been replaced by combination gasoline station and convenience store ("C-stores"). Natural gas is distributed to residential consumers and to many industrial companies by local gas utility companies.
3. **Service Industry:** companies in this segment are primarily known for supporting the upstream segment -- by owning and operating equipment such as drilling rigs; supplying goods such as well casing (pipe); and performing services such as fracturing wells and conducting seismic surveys. Some companies manufacture their own equipment. The scope of these companies range from privately owned firms that operate in a limited region to multinational corporations with activities, employees, and customers around the world.

4.41.1.1.3 (12-03-2013)

Requesting Assistance from Specialty Groups and Subject Matter Experts

1. Petroleum Technical Subject Matter Experts are available for consultation through various Issue Practice Groups and International Practice Networks.

2. In the course of an examination, the examination will probably require assistance from a specialist. Agents should follow guidelines for mandatory referrals <http://lmsb.irs.gov/hq/mf/NewHire/JobAids/SRSTA.asp>.
3. When a specialist is needed, the examiner should involve the specialist early in the examination process. The specialist will greatly assist the examiner in identifying, planning and developing the issues. Referrals to specialists are made on the Specialist Referral System. Refer to IRM 4.60.6.3, *Specialist Referral System*. <http://irm.web.irs.gov/Part4/Chapter60/Section6/IRM4.60.6.asp#4.60.6.3>
 - A. **Engineer Referrals:** Referrals should be made during the early stages of each examination when significant and complex engineering issues are noted on the return.
 - B. **Computer Audit Specialist Referrals:** In the course of the examination, the agent should request the assistance of a Computer Audit Specialist (CAS). The CAS should be involved in the review of records for record retention evaluations and to assist the agent as appropriate throughout the examination. The CAS is also trained in the use of statistical sampling techniques. In those instances where the volume of records is such that a 100 percent examination is not feasible, statistical sampling should be considered.
 - C. **International Examiners:** Referrals to International Examiners (IE) are made on the Specialist Referral System during the early stages of each examination initiated when it is ascertained that the taxpayer is engaged in business outside the United States either directly or through related, controlled, or controlling affiliates. See IRM 4.60, *International Procedures Manual*. Since IRC 482 allocations may be possible in these cases, it is important that the referral reflect all such subsidiaries controlled by the corporation being referred.
 - D. **Financial Products Specialists:** Referrals should be made during the early stages of each examination when significant and complex financial product issues are noted on the return. These may include futures, options, government securities, and other financial products.
 - E. **Excise and Employment Tax Specialists:** During the examination when the agent discovers claims for excise and employment tax payments, the assistance of a specialist should be requested through the team manager.
 - F. **Tax Exempt and Government Entities (TEGE) Specialists:** Contact the agent's manager when complex and extraordinary deductions relating to matters that involve Employee Plans (pension and profit sharing plans), Exempt Organizations, Indian Tribal Governments, Tax Exempt Bonds or Federal State and Local Governments are encountered. The agent's manager must contact the Office of Indian Tribal Governments to coordinate any first contact with an entity owned by an Indian tribal government or situated on Indian land. See <http://tege.web.irs.gov/templates/TEGEHome.asp>.

4.41.1.1.4 (12-03-2013) **Petroleum Industry Statistics**

1. Examiners are encouraged to become familiar with the numerous petroleum industry trade publications. Frequently, these publications will contain industry statistics that are very useful in the examination of oil and gas issues.
2. For instance, the selling prices of domestic and foreign crude oils are sometimes shown in periodicals. A comparison of these industry average prices with the purchase price paid to a Controlled Foreign Corporation (CFC) will sometimes point out "pricing" problems between related entities. Another use of industry statistics is a comparison of drilling costs with the costs reported on the tax return being examined. While average drilling cost statistics are not reliable for purposes of making adjustments, comparisons will often point out problems that might not be easily identified under normal examination techniques. An apparent excessive drilling cost may be easily explained as being due to accidents, such as losing the drill string. On the other hand, the excessive cost may be the result of excessive charges or due to the inclusion of lease costs in the intangible drilling costs (IDC) use billed to joint owners.
3. The wide use of industry statistics can materially reduce examination time. Furthermore, their use as a testing tool will frequently identify problem areas that would not be found using normal examination techniques. IRS engineers will usually have access to current petroleum industry statistics.

4.41.1.1.5 (12-03-2013) **State Regulation of Oil and Gas Production**

1. Oil and gas exploration and production is closely supervised and regulated by the various state agencies. Virtually every state has different requirements, and the agencies within each state that administer the laws are varied.

Example:

In Texas the Railroad Commission administers the laws relating to oil and gas exploration and production. In Oklahoma it is the Corporation Commission; in Louisiana it is the Office of Conservation.

2. One of the resources available to examiners with respect to a description of the various actions taken on oil and gas properties are the various state permits required to be obtained before any type of drilling, exploration, deepening, plugging and abandoning, or other activity can be done. The applications for the various permits and reports of work performed filed with the state agencies provide a wealth of helpful information, such as dates of notices of intention to drill a well, type of well, legal description of property, estimated total depth, and other details.
3. Production severance tax rates imposed on oil and gas production by the various states have not been shown on the attached schedule because of the many differences in the rates and manner in which applied. This knowledge is, however, important to the examiner because, in many instances, investors will report the net amount of the proceeds received from the sale of oil and gas as gross income subject to depletion. Gross income, for depletion purposes, means gross revenue before payments of severance taxes. The tax rates, and how they are applied, may be obtained from the taxpayer or from the state agency that administers the tax.

4.41.1.2 (12-03-2013) **Acquisitions**

1. This section provides guidelines for determining the cost of oil producing and non-oil producing property.
2. First, oil and gas acquisition transactions are described in general.
3. Second, economic transactions involving oil and gas interests and the tax consequences as they relate to examination techniques are described in detail. See *IRM 4.41.1.2.2* and *IRM 4.41.1.2.3*.
4. For purposes of this section, the terms "mineral property" or "oil and gas property" refer to a real property interest. A major factor in the examination of oil and gas records is the verification of the cost of a property. The cost (basis) of the real property interest is recovered through depletion. This cost also provides the basis for the computation of gain or loss on the sale of all or part of such property. If the property is producing, the cost or basis of the associated equipment is recovered through depreciation. If the property is nonproducing, the cost may be recoverable upon expiration of the contract or by virtue of its worthlessness demonstrated by unsuccessful development. Refer to Exhibit 4.41.1-3, *Useful Examination Techniques - Lease Acquisition Costs*.

4.41.1.2.1 (12-03-2013) **Acquisition Transactions**

1. The examination of an oil and gas producer (operator) is made difficult by the use of non-uniform accounting procedures. Not only is each taxpayer different but the methods used to record transactions vary. This is because oil and gas producing companies, depending upon their size, keep the type of records they deem sufficient for their needs.
2. In planning the examination, note whether the return indicates new acquisitions or producing leases. Experience shows that new nonproducing properties are acquired each year, and numerous complications may arise in connection with such acquisitions. A wide variety of problems is created through the various contractual agreements made to acquire and explore oil properties. For this reason, the new properties and the way they are acquired should be closely examined.

4.41.1.2.1.1 (12-03-2013)

Interests in the Mineral Deposits

1. The type of ownership interest determines the extent to which the investor and operator will share in the income from oil and gas production. The various kinds of property interests or rights constitute the ownership of the oil and gas extracted. IRC 614 defines a property as each separate interest owned in each mineral deposit in each separate tract or parcel of land.
2. An understanding of the tax consequences of oil and gas transactions requires a clear concept of mineral interests and their interrelationships:
 - A. *Landowner Interests* are those in which the landowner owns the land in fee, including the minerals on and beneath the surface. The landowner may sell or otherwise dispose of subsurface or mineral rights without relinquishing surface rights. Ownership of the mineral rights, which includes the total of all rights to the oil and gas in place, is of primary concern. These rights, separately or jointly held, may include executory rights -- i.e., rights to negotiate, bargain, and sign the oil and gas lease, lease bonus rights, delay rental rights, royalty rights, and operating rights
 - B. *Non-landowner Interests* are those mineral rights held by someone other than the landowner. In this case, the party can sell or otherwise dispose of ownership interest in the minerals. When such dispositions are made, other interests and new owners come into the picture, each having a piece of the mineral deposit. These interests entitle the owners to share in the total production from the property.

4.41.1.2.1.2 (12-03-2013)

Landowner and Fee Royalty Owner

1. A landowner generally owns what is known as a "fee interest," which consists of the ownership of both surface and mineral rights. The landowner can sell or lease all or any part of the land or minerals. A lease agreement usually provides for a cash consideration, or bonus, and a royalty to be paid to the landowner. The lease usually contains a provision for the lessee to pay a delay rental for each year development is not started or forfeit the lease.
2. Cash bonuses received upon the execution of an oil and gas lease are regarded, for income tax purposes, as advance royalties. The Supreme Court in *Anderson v. Helvering*, 310 US 404, 409 (1940); 24 AFTR 967; 40-1 USTC 553 stated "cash bonus payments, when included in a royalty lease, are regarded as advance royalties, and are given the same tax consequences." Bonus payments are not subject to percentage depletion after August 16, 1986 because of the enactment of IRC 613A(d)(5).
3. In any subsequent year during the term of the lease, the receipt of the delay rental will be ordinary income to the landowner on which no depletion is allowable. The delay rental is not an advance payment for oil but is in the nature of rent paid for the privilege of deferring development. See Treas. Reg. 1.612-3(c)(2) *IRM 4.41.1.2.2.2 Delay Rentals*, discusses how the lessee should treat its payment to the landowner.
4. If drilling results in a producing well, the landowner will receive periodic payments for its share of the production in accordance with the terms of the lease. These payments, called royalties, are ordinary income to the landowner. This income is subject to percentage depletion to the extent provided in IRC 613A and the regulations provided thereunder, provided that percentage depletion is greater than cost depletion. This will usually be the case when the fee interest in the entire property is acquired for the purpose of using the surface rights and, as a result, the landowner will have no basis in the mineral rights.
5. If there is no production and the lease expires, the depletion previously allowed against bonus income must be restored to income in the year the lease terminates. However, restoration is not required if there is no production, the lease has expired, and the taxpayer who took depletion on the lease bonus has completely divested the property prior to the expiration of the lease without production. See Treas. Reg. 1.612-3(a)(2).
6. Termination of the lease may be indicated by the absence of the delay rental in the income of the current return and its presence in the prior return.
7. If, prior to expiration, the lease was extended and a bonus was paid for such extension, percentage depletion would be allowable on the bonus only if reportable prior to August 16, 1986. See Treas. Reg. 1.613A-3(j). After that date, taxpayers may still compute cost depletion on these payments. Restoration to income of bonus depletion would not be required with respect to the original lease or the extension unless the lease terminated without production and depletion had been deducted. See Treas. Reg. 1.612-3(a)(2). At such time, the allowed depletion on the original lease and renewal (top lease) should be included in income.
8. The landowner can sell all or any part of the mineral rights. If a fee interest in the minerals is sold, the sale is governed by the provisions of IRC 1231. If the sale of the property otherwise qualifies as provided in IRC 1231, a long-term capital gain is realized on the sale of minerals. There is no cost basis unless one of the following conditions exists:
 - A. Seller's cost included a stipulated amount for mineral rights
 - B. Seller's basis was the result of an estate tax valuation in which minerals and surface were valued separately
 - C. Seller's cost basis can be properly allocated between surface and minerals because of substantial evidence of value attributable to the minerals at date of acquisition
9. The basis is applicable in the event of a sale or for computing cost depletion. Generally, the basis of minerals should not be allowed as an abandonment loss where the owner also owns the land.
10. The agent should inspect the prior-year return. The prior-year return may disclose a delay rental which does not appear in the current return. This indicates for the current year either unreported income from delay rental or a lapsed lease which may require restoration of bonus depletion by the lessor.
11. Experience indicates that bonus income and royalty income are usually reported, but bonus depletion is rarely restored to income.

4.41.1.2.1.3 (12-03-2013)

Fee Royalty Owner

1. The position of a fee royalty owner is the same, irrespective of surface rights ownership. The owner may lease interest, receive a bonus or delay rentals, receive income from production, and may sell all or any portion of royalty interest.
2. Rights or interest in production may be created by the owner of the minerals and consist of two major categories:
 - A. *Royalty Interest* entitles its owner to share in the production from the mineral deposit, free of development and operating costs, and extends undiminished over the productive life of the property. See Treas. Reg. 1.636-3(a)(2) for situations where a royalty will be treated as a production payment.
 - B. *Working Interest* also entitles its owner to share in the production, but this owner must bear its share of the development and operation costs.
3. Royalty and working interest owners may, subject to certain restrictions, sell or otherwise dispose of all or part of their respective interests in the total production. When this happens, there are additional subdivisions of the total production known as overriding royalties, oil and gas production payments, net profits interest, carried interest, and other income items.
4. *Exhibit 4.41.1-2* shows the basic divisions of production from oil and gas. Beginning with the landowner, this is carried through a few of the various interests which may be carved out of the original ownership of the minerals in place.

4.41.1.2.1.4 (12-03-2013)

Royalties

1. The fee royalty generally will represent a negotiated amount between the landowner's retained interest for the oil or gas in place and the lessee oil company. Traditionally, the amount of the fee royalty is $\frac{1}{8}$ of the production from the property, however, the amount can vary. Royalty rates of $\frac{1}{6}$, $\frac{3}{16}$, and $\frac{1}{4}$ are also common. Assuming that a $\frac{1}{8}$ royalty interest is retained, the remaining $\frac{7}{8}$ is generally conveyed as working interest to an operator in consideration for a cash bonus and development of the property.

Another type of royalty is known as an override, which is an interest reserved or carved out of the $\frac{7}{8}$ working interest, the life of which is coexistent with that of the lease or working interest. Usually the life of the fee royalty is perpetual. However, its life may be limited by the terms of the instrument under which it was created. In some areas, the life of a fee royalty may be governed by state law.

4.41.1.2.1.5 (02-19-2008)

Royalty Interest

1. There are two types of royalty interest which may be acquired from the landowner. In one, the landowner conveys by royalty deed the title in fee simple to all or a portion of the landowner's royalty interest in the property. The deed may describe the interest sold as a fraction of the "landowner's royalty" or a number of "royalty acres." Each royalty acre is entitled to a fraction (usually $\frac{1}{8}$) of the production attributable to that acre, free and clear of production costs. This transaction may take place before or after leasing. The interest thus assigned is a fee royalty. In the other type, the landowner, after leasing, may sell portions of royalty interest in the lease. This is not a fee interest, but a share of the production of oil or gas under this lease, and expires with the termination of the lease. In this respect, it is similar to an overriding royalty.
2. The royalty interest is purchased from the landowner, who may sell his/her entire interest, or any fraction thereof. Usually this is after a lease has been granted for the development of the property and there appears to be a prospect of future production. The purchase is usually made by an investor or royalty dealer. The principal issues encountered here are the treatment of acquisition costs and deductions for worthlessness losses claimed as a result of unsuccessful exploration.
3. The small investor may maintain ledger control accounts of producing royalties and nonproducing royalties. These are supported by separate accounting for each property interest (particularly producing properties) and usually showing the property interest owned. The landowner usually has the recorded instruments of conveyance for inspection if they are needed.
4. The larger investor may maintain control accounts of Producing Royalties and Nonproducing Royalties, and a subsidiary record known as a Royalty and Fee Land Record for each royalty interest owned. Such record shows the property, location, description, interest owned, from whom acquired, date acquired, cost, lease information, and record of rentals received. When verifying cost for an investor who has claimed an abandonment loss, the agent should verify that the cost has been removed from the subsidiary record as well as the control account. The cost may have been written off for tax purposes without appropriate charges on the books. When a royalty becomes a producing property, the investment account is transferred from the Non-producing Royalties account to the Producing Royalties account. At this point, the property should be shown in the return as income producing property subject to depletion.
5. The royalty dealer usually watches oil company leasing operations very closely. When an area of interest is identified, the dealer begins purchasing the fee royalties in the area. The dealer usually has certain investors with whom it regularly deals, and to whom a portion of the royalty interest is acquired, retaining a small fraction as its own investment. The dealer usually sells a portion of the royalty obtained for a greater sum than the entire cost of the interest obtained. A fraction of the cost corresponding to the fractional interest is retained. Thus, if a dealer purchases $\frac{1}{16}$ royalty ($\frac{1}{2}$ of the landowner's $\frac{1}{8}$) for \$8,000 and sells a $\frac{3}{64}$ interest ($\frac{3}{4}$ royalty), the basis for the portion sold is \$6,000. The basis of the $\frac{1}{64}$ interest retained is \$2,000.
6. The investor or dealer should capitalize, as part of the cost of royalties, commissions, title examination and recording fees, travel expense, or other expenses incurred in connection with the acquisition of the royalty interest. If a single sum was capitalized as cost of the royalty, this may indicate that some of the above acquisition costs were charged to expense. This would require an analysis of certain expense accounts.
7. Amounts paid or incurred for geological and geophysical before enactment of the Energy Tax Incentives Act of 2005 should be capitalized pursuant to Rev. Rul. 83-105. However, amounts paid or incurred for geological and geophysical activity after enactment of the 2005 Energy Bill should be amortized over two years under IRC 167(h). See *Exhibit 4.41.1-28*. After May 17, 2006, the geological and geophysical amortization amount for certain integrated oil companies was extended to five years. See *Exhibit 4.41.1-29*.
8. Acquisition costs must also be allocated to the cost basis of the specific royalties acquired. Where multiple royalties are acquired, it may be difficult to determine the accuracy of the taxpayer's allocation of travel, geological, geophysical expenses, and general office expenses.

4.41.1.2.1.6 (07-31-2002)

Oil and Gas Leasing Contracts

1. The interests of an investor or operator in mineral deposits as well as the rights to share in the production from such deposits are governed by the terms of a leasing contract or supporting agreement. Through these contracts there may be numerous assignments, conveyances, and dispositions of interest or rights.
2. By analyzing the various leasing contracts and the resulting tax consequences, the examiner can pick up leads to potential tax adjustments. A substantial amount of examination time can be spent on such analyses and is often a productive and important examination step.
3. The oil and gas lease has progressed from a simple instrument to a complex document. Most leases contain eight principal elements:
 - A. **Principal parties**
 - B. **Date** — Determines the precedence of documents.
 - C. **Habendum clause** — Fixes the duration of the lease interest. If production is not attained in the time specified, often called the primary term, the lease expires by its own terms.
 - D. **Granting clause** — Specifies what the lessor has granted and the consideration paid.
 - E. **Royalty clause** — Sets out the principal inducement, aside from the cash consideration, for the property owner to sign the agreement. The landowner's royalty (usually $\frac{1}{8}$ of gross production) is free and clear of any drilling or operating expenses.
 - F. **Drilling and delay rental clauses** — One of the primary considerations in an oil and gas lease is the early development of the property. Drilling and delay rental clauses specify the manner in which early drilling can be deferred. This may be done for a specified period by the payment to lessors of delay rentals. However, drilling cannot be deferred past the primary term of the lease without voiding the lease.
 - G. **Description of the property** — An accurate description of the property is necessary. A system of land measurements known as the "Rectangular System" is used today in most oil-producing states. Areas of some oil-producing states, however, are not laid out in this system but are surveyed in parcels, sometimes in irregular geometric patterns.
 - H. **Special considerations** — Additional clauses may be inserted in a lease agreement to more fully describe the rights and duties of the parties; such as, drilling restriction near buildings, right to unitize or pool lands, or right to use surface facilities.
4. While most leasing contracts may contain these basic elements, variations in their wording and meaning abound. These contracts vary to such an extent that it would be impractical to talk in terms of a "typical contract." This very feature emphasizes the importance of the agent's analysis.

4.41.1.2.2 (07-31-2002)

Lease and Leasehold Costs

1. A lease is a contract between a landowner or mineral owner (lessor) and a second party (lessee). The lessor grants to the lessee the exclusive right to drill for and produce oil, gas, or other minerals on the property described in the lease. A lease usually provides for:
 - A. Cash (lease bonus) payable to the lessor upon the execution of the lease and approval of the title

- B. Specified term of years, usually from three to ten years
- C. Delay rental for each expiring year during which the lessee has not commenced drilling operations
- D. Lease cancellation if lessee does not pay delay rental by the due date
- E. Basis for division of oil and gas produced between the lessor and the lessee
- F. Continuation of the contract between the lessor and lessee as long as oil or gas is produced from the property

2. The lessor's share of the production is known as the royalty interest or landowner's royalty. This is usually $\frac{1}{8}$ of the oil or gas produced which, by the terms of the lease, is free of all costs of development and operation. The lessee usually acquires $\frac{7}{8}$ of the oil or gas produced. This is the working interest and is burdened with the costs of development and operation. The amount of production designated as the landowner's royalty has become fixed by custom. However, in various parts of the United States, $\frac{1}{5}$ or $\frac{1}{6}$ may be the landowner's royalty, particularly if the landowner is bargaining from a favorable position. In addition, such landowner may be able to obtain a larger lease bonus (in a lump sum or installments). In lieu of a bonus, the lessor and lessee may prefer a minimum (guaranteed) royalty arrangement. This might be the most advantageous position for both parties.
3. The lessee does not undertake a specific obligation to develop the property or to pay delay rentals, but does agree that the lease will expire if the property is not developed or rentals are not paid. Ordinarily, the lessee can abandon the property without penalty. It is customary, however, for the lessee to formally terminate the lease if the lessee desires to surrender the property without development.
4. Leases are frequently acquired in what is known as blocks. The usual procedure is for geologists and geophysicists to make certain preliminary surveys of the surface conditions. Core drilling along public highways and other forms of study of the topmost layers of the earth may be indicative of the patterns of folds in the earth's strata at greater depths. If the survey indicates the area is promising for the development of oil or gas, oil company agents acquire leases covering the desired area. Further geological and geophysical work is performed to determine the most favorable portions of the area and whether subsurface structures appear favorable for drilling. Based on this information, certain portions of the acreage may be dropped, and the remainder retained for future development and operation.
5. In many parts of the country, the mineral or executory rights under a particular tract of land may be owned as an undivided interest by several persons. Each person may lease only the part owned. As a result of this, as many as three or four different operators frequently acquire an undivided interest in the leasehold under a tract of land. An owner of a $\frac{1}{8}$ interest in the minerals may sign a lease instrument which is exactly the same as one signed by an owner of 100 percent of the minerals. Thus, the leasing document does not indicate the extent of ownership of the signatory parties. To determine ownership, it may be necessary to study a division order (if property is productive) or an abstract.

4.41.1.2.2.1 (07-31-2002) Installment Bonus Payments

1. When examining the lease record for properties acquired during the year, pay particular attention to the amount of rent per acre per year. You may find something to indicate payments other than normal delay rental. In most areas, delay rentals are relatively small compared to lease bonuses. The period covered by the lease should be noted, as well as any provisions with respect to terms and expiration. The purpose is to be sure an installment bonus is not recorded as a delay rental.
 - A. If it is found that the annual payments are for a fixed number of years regardless of production and if the lessee is unable to avoid such payments by terminating the lease, such annual payments are installment bonus payments and should be capitalized by the lessee as part of the cost of the lease. These payments would be found in the lease rental expense account, but the nature of the payments would be determinable by examination of the provisions of the lease itself.
 - B. However, a cash-method taxpayer who receives an installment bonus contract as consideration for an oil or gas lease must include its value in gross income for the year in which the lease is executed if the obligation is transferable and readily saleable. See Rev. Rul. 68-606, 1968-2 CB 42.
 - C. A production payment retained in a leasing transaction is treated as bonus paid in installments. See IRC 636(j) and Treas. Reg. 1.636-2(a). The production payment is not taxable when the lease is made by the landowner, only as oil income is received.

4.41.1.2.2.2 (10-01-2005) Delay Rentals

1. Oil and gas lease agreements generally provide for the lessee to begin drilling for oil and gas on the property within one year after the granting of the lease. If drilling has not begun within this period of time, the lease agreement will either expire or provide for the payment of a sum of money in order for the lessee to retain the lease without developing the property. These payments are known as "delay rental" payments and are made in order to be granted additional time in which to drill and develop the leased property. The purpose and the rights granted by the payments of the rental must be examined to determine whether the payments are actually "delay rentals," lease bonus, or royalty payments. Delay rentals are not payments for oil or gas to be produced. They are paid for the privilege of retaining the lease without drilling for up to another year.
2. Delay rentals are ordinary income to the recipient and are not subject to the depletion deduction. See Treas. Reg. 1.612-3(c). The payment of delay rentals are preproduction costs which are required to be capitalized to the depletable basis of the lease pursuant to IRC 263A if the lease is held for development or if development is reasonably likely at some future date. See Treas. Reg. 1.263A-2(a)(3)(ii) and TAM 9602006.

4.41.1.2.2.3 (10-01-2005) Capital Expenditures

1. A small operator may keep a simple set of records. A large operator will probably keep a rather complex system of records. Each operator maintains separate accounts of producing and nonproducing properties. Each usually keeps the operation of each lease in such a manner that his/her income tax return can be prepared showing each property as a separate operation. The large operator usually has a greater number of control accounts and more detailed subsidiary records.
2. The acquisition of properties involves such accounts as Producing Royalties, Nonproducing Royalties, Undeveloped Leases Control, and Producing Properties-Leasehold Control. Separate control accounts may be carried for Equipment and Intangible Drilling and Development Costs. Each control account is supported by records.
3. The subsidiary ledger for nonproducing leases is generally maintained in accordance with geographic location by states, subdivided by counties, with each lease bearing an identification number. This record shows the name of the lease, number of acres covered, legal description, county, state, bonus paid, date of lease, term expiration date, the interest owned, royalty, override, from whom acquired, rental per acre, by whom title examined, other interests, assignments, and rental payment record. This lease record provides a quick and ready reference to any nonproducing property owned without the necessity for consulting the lease file; however, some taxpayers do not maintain a separate lease file.
4. The total costs of nonproducing properties are recorded in the control account, and a subsidiary record of cost by leases is kept. Some companies make direct charges to the subsidiary nonproducing lease records, while others enter charges in a suspense account for accumulation, and then clear the suspense account by a single entry to the subsidiary lease record.
5. In order to ascertain that all capital costs are included in the lease record, an analysis of the charges to the lease record or to the suspense account should be made. The items which should appear in these accounts on each lease are the lease bonus, abstract costs, abstract examination fee, filing fee, delay rentals, and travel expense. In addition, there should be charged any commissions paid for obtaining the lease. The cost of a quiet-title suit should also be capitalized.
6. As leases become productive, the record is transferred to producing lease accounts. The acquisition costs of the underdeveloped leases are transferred to leasehold costs on the producing lease records, to which other costs, capital in nature, in connection with development are added. When a lease terminates without production, the account is transferred to an account for surrendered and expired leases.

7. Generally, lease bonuses are properly capitalized by the payor. It is quite common to find that other items have not been capitalized by the taxpayer and must be capitalized by the agent during the examination. This requires the close examination of certain accounts and records of expenditures.

8. *Exhibit 4.41.1-5* is a classification of expenditures in acquisition, development, and operation of oil and gas leases.

4.41.1.2.2.3.1 (12-03-2013)

Capitalization of Non-direct Costs under IRC 263(c) or IRC 263A

1. "Non-direct" costs generally fall into three broad categories: indirect, overhead, and interest expense. In the oil and gas industry the requirement to capitalize these types of costs is primarily governed by:

A. IRC 263(a)

B. IRC 263A - Uniform Capitalization Rules (UNICAP) for Indirect Costs and Interest Expense

C. Temporary Treas. Reg. 1.263(a)-0T through 1.263(a)-3T, which are known as the "new tangible regulations" are generally effective for taxable years beginning on or after January 1, 2014. Taxpayers may also elect to apply these temporary regulations for taxable years beginning on or after January 1, 2012. See T.D. 9564, Notice 2012-73 and Announcement 2013-7. LB&I Directive dated March 15, 2012 (superseded March 22, 2013) addresses whether an examination of the type of costs covered by the temporary regulations should be conducted, including those for tax years before January 1, 2012. See <http://www.irs.gov/Businesses/UPDATEDLBIDIRECTIVEforTPsIRC263a>.

2. **IRC 263(a).** Intangible Drilling and Developments Costs (IDC) do not draw non-direct costs under UNICAP because of an exception provided in IRC 263A(c)(3). However, IRC 263(c) still requires an allocation of the portion of overhead that is "directly or clearly related" to IDC-type activity. The standard is discussed in PLR 8640006 which cited several court cases. The following excerpts indicate that it is based on facts and circumstances:

- In the oil and gas industry no uniform pattern of business operations exists and each taxpayer's drilling operations will have to be carefully studied to ascertain the types of overhead expenditures that are directly related to IDC. [T]he portions of general overhead incurred by [a taxpayer] which are clearly related to or identifiable with drilling and development activities, are thus properly identifiable and treatable as IDC for purposes of section 263(c) of the Code .*
- Each item of general and administrative overhead must be examined to determine whether it is, in whole or in part, related to the drilling and development activity.*

Example:

A portion of the rental expense of the headquarters of a small oil and gas company may be incident to and necessary for the drilling and development activity where the headquarters facilitates the coordination of the company's various activities, including drilling.

Example:

A substantial portion of the president's salary and related overhead may also be attributed to IDC. The amount of rental expense, which is attributable to IDC, might be determined on the basis of actual floor space devoted to coordination of the company's drilling and development activities.

Example:

A portion of the legal fees incurred by an oil company for services provided by an attorney retained by the company is incident to and necessary for the drilling of wells to the extent that these expenditures would be incurred in connection with negotiating and drafting drilling contracts. The amount of legal fees attributable to IDC might be determined on the basis of the proportion of time spent by the attorney in negotiating and drafting the drilling contracts [versus other billable activities].

Example:

Also, included in IDC would be the portion of the costs, including overhead of geologists, and field engineers, together with support clerical staff whose major function is to acquire new oil sites and supervise the drilling and development of such sites.

Example:

In the event that a relationship is established between an overhead item and both the drilling and development activity and other activities of the taxpayer, such item may appropriately be allocated on some reasonable basis between IDC and other activities.

Example:

A major oil company would operate substantially differently from a small independent producer. In that case only the cost related to the departments directly involved with lease acquisition, contract negotiation and drill site development can be attributed to IDC.

- Since IDC is fully deductible in many circumstances, examiners should perform a risk analysis of switching ordinary expense to IDC, including the impact on AMT liability. The examiner can also ask the taxpayer to identify how much, if any, overhead was added to its direct IDC costs (primarily fees paid to drilling contractors). Companies that serve as the operator of joint ventures routinely charge overhead on IDC to the other working interest owners. A review of Joint Operating Agreements should reveal the level of agreed-upon IDC overhead. If the overhead level for IDC on wells the taxpayer drills on its own account is substantially less, it should be asked to provide an explanation. Generally speaking, even though the amount of overhead is based on facts and circumstance, for most operators it will be at least 5 percent of their direct IDC costs.

3. **IRC 263A.** The UNICAP rules generally require taxpayers that produce real property and tangible personal property to capitalize all the direct costs of producing the property and the property's properly allocable share of indirect costs, regardless of whether the property is sold or used in the taxpayer's trade or business. To capitalize means to include costs in the basis of property that is produced or in inventory costs rather than to deduct them as a current expense. The costs are recovered through deductions for depreciation, depletion, amortization, or cost of goods sold when the property is placed in service, sold, or otherwise disposed of.

A. The regulations under Treas. Reg. 1.263A-1 through 1.263A-6 provide guidance to taxpayers that are required to capitalize certain costs under IRC 263A. These regulations generally apply to all costs required to be capitalized under IRC 263A(a) except for interest. The capitalization of interest is covered under 263A(f) and Treas. Reg. 1.263A-8 through 1.263A-15.

B. Interest expense is capitalized when real property, such as oil and gas property, is "produced" . The amount of interest expense will depend on an interest rate reflecting an "avoided cost of debt" , the "production period" of the asset, and the cost of the asset. See Treas. Regs. 1.263A-8 through 1.263A-12 in general and 1.263A-13 in particular for oil and gas activities.

C. Interest expense is also capitalized during the production of personal property that has: MACRS class life of 20 years or more; or, estimated production period of more than two years; or, an estimated production period of more than one year and the estimated cost of production exceeds \$1 million.

D. Companies in the upstream oil and gas sector routinely produce tangible property in the form of wells, separators, tank batteries, and gathering lines which are generally considered personal property since the MACRS class life is only 14 years (Asset class 13.2). Whether interest must be capitalized will depend on the production period and estimated cost. Those items are discussed at length in Treas. Reg. 1.263A-13(b)(1) - (3) and (c)(1) - (7). An extensive review of these regulations is beyond the scope of this IRM.

E. A similar analysis will be required for assets that are placed into service in such MACRS asset classes as Offshore Drilling (13.0), Drilling of Oil and Gas Wells (13.1), Petroleum Refining (13.3), and Natural Gas Production Plant (49.23) since the class life for each is less than 20 years. On the contrary, since the class life for assets used in Pipeline Transportation (49.21), Gas Utility Distribution Facilities (49.21), Gas Utility Trunk Pipelines and Related Storage Facilities (49.24) and Liquefied

Natural Gas Plant (49.25) is 20 years or more, interest expense is capitalized regardless of the estimated production period or estimated cost.

- F. Oil and gas companies in the upstream sector also produce offshore platforms. Whether a "jacket type" platform is an "inherently permanent structure" and should be considered real property for purposes of IRC 263A(f), was addressed in CCA 201211011 (July 1, 2011, transmitting WTA-N-110835-98 (1998)). While a floating deepwater platform is affixed to the seabed in a different manner than a jacket type platform, it has some of the same characteristics. If the taxpayer treated any platform as not being real property for purposes of IRC 263A(f) the examiner should consider contacting Local Counsel or a Subject Matter Expert for IRC 263A.
- G. The total UNICAP costs that have been added to depreciable property that was placed in service during the tax year is to be reported on Line 23 of Form 4562, Depreciation and Amortization. If the amount seems negligible a review of the taxpayer's methodology in arriving at the figure may be warranted.
- H. To determine if the taxpayer is including any UNICAP costs in the basis of its leases, examiners should focus on high cost leases (such as offshore tracts) that recently underwent their initial drilling phase.

Example:

Assume that the appropriate "avoided debt" interest rate for a taxpayer is 5 percent. If a lease with a \$20 million basis underwent initial drilling for 90 days during the year, then approximately \$250,000 of interest expense should have been added to depletable basis [$\$20 \text{ million} \times 5 \text{ percent} \times (90 \div 365 \text{ days})$] and subtracted from interest expense.

- I. Companies in the natural gas marketing and transportation sectors may acquire gas for resale. Treas. Reg. 1.263A-1 states that IRC 263A does not apply to any costs incurred by a taxpayer relating to natural gas acquired for resale to the extent such costs would otherwise be allocable to cushion gas. Cushion gas is the portion of gas stored in an underground storage facility or reservoir that is required to maintain the level of pressure necessary for operation of the facility. However, IRC 263A applies to costs incurred by a taxpayer relating to natural gas acquired for resale to the extent such costs are properly allocable to emergency gas. Emergency gas is natural gas stored in an underground storage facility or reservoir for use during periods of unusually heavy customer demand. Other gas in the storage facility that is available to meet customer demand (often called "working gas") is subject to IRC 263A.

4. Temporary Regulations for 1.263(a).

- A. Temporary regulations 1.263(a)-0T through 1.263(a)-3T, which are known collectively as the "new tangible regulations" are effective for tax years beginning on or after January 1, 2012. See T.D. 9564. they are set to expire December 23, 2013, but they may be replaced by final regulations on or before that date. LB&I Directive dated March 15, 2012 (superseded March 23, 2013) addresses whether an examination of the type of costs covered by the temporary regulations should be conducted, including those for tax years before January 1, 2012; refer to <http://www.irs.gov/Businesses/UPDATEDLBIDIRECTIVEforTPsIRC263a>.
- B. The following discussion assumes that an examination of these types of costs is permitted by the aforementioned directive.
- C. Because of the length of the temporary regulations, an exhaustive review will not be provided here; however, three important areas impact the oil and gas industry: whether an amount is paid to acquire or produce a unit of real or personal property (see 1.263(a)-2T); whether an amount is paid to *improve* a unit of real or personal property, as opposed to *repair* the unit of property (see 1.263(a)-3T); how to determine an appropriate unit of property (also covered by 1.263(a)-3T).
- D. Examiners will find that the regulations under IRC 263A are referenced throughout the new tangible regulations. For example, 1.263(a)-2T(f)(2)(iv) states that amounts paid for employee compensation (within the meaning of Treas. Reg. 1.263(a)-4(3)(4)(iii)) and overhead are treated as amounts that do not facilitate the acquisition of real or personal property. However, the temporary regulation refers to IRC 263A for the treatment of employee compensation and overhead costs required to be capitalized to property produced by the taxpayer or to property acquired for resale.
- E. Example 4 of 1.263(a)-2T(f)(4) states that although costs paid for geological and geophysical services are inherently facilitative to the acquisition of real property (in the form of an oil and gas lease), taxpayers are not allowed to include those amounts in the basis of the real property acquired. Rather, they must capitalize the geological and geophysical costs separately and amortize them as required under IRC 167(h).
- F. Examiners who focus on refinery improvements and turnaround costs will want to closely review the guidelines for unit of property for "Plant Property" that are found in Treas. Reg. 1.263(a)-3T(e)(3)(ii). they may also want to review Rev. Proc. 2013-24, IRB 2013-22, which provides safe harbor definitions of units of property and major components for steam or electric power generating facilities, to see if useful parallels can be found.
- G. Examiners who focus on pipeline improvements and repairs will want to closely review the statements regarding unit of property for "Network Assets" found in Treas. Reg. 1.263(a)-3T(e)(3)(iii). Agents are encouraged to contact industry subject matter experts for the latest developments in this technical area.

4.41.1.2.3.2 (12-03-2013)

Geological and Geophysical Expenditures

1. In general geological and geophysical ("G&G") expenditures are costs incurred by an oil and gas exploration and production company to obtain, accumulate, and evaluate data that will serve as the basis for the acquisition or retention of oil and gas properties. "G&G" expenditures are usually associated with a survey, such as a seismic, magnetic, or gravity survey conducted by a specialized service company. These expenditures can also include the cost of acquiring well logs and core data, sometimes called "bottom-hole data", which pertains to wells drilled by other companies.
2. In recent years the capability of seismic technology has increased dramatically, especially in regards to offshore exploration, drilling and production activities. Data processing and digital imaging have been greatly enhanced by the use of extremely powerful computers and advanced computer modeling techniques. The clarity of seismic surveys has been greatly increased with the advent of "3D" seismic surveys which are achieved by running tightly spaced seismic lines over the entire survey area. In some very large oil fields 3D surveys are conducted periodically (known as "4D" surveys) and evaluated to determine the extent which fluids have moved within the reservoir over time in response to the withdrawal of oil and gas and the injection of water. During drilling operations, sensors that are located in the drill string can collect seismic data "ahead of the drill bit" which can be used to optimize drilling parameters such as mud weight, drill path and casing points.
3. G&G can be both direct and indirect. An example of a direct cost would be the licensing fee paid to a vendor for the right to use a seismic survey it conducted. Examples of indirect costs would be the salaries of employees who evaluate the survey and overhead of the department which performs the computer processing of the survey. On occasion the evaluation and processing is done by vendors or consultants. Examiners should be aware that for financial accounting purposes such costs are routinely charged to expense. In contrast, for tax purposes, G&G expenditures are generally considered capital expenditures.
4. G&G expenditures that are charged to current expense should be closely examined. They are frequently charged to "Other Professional Expenses" on Line 26 or may be deducted as intangible drilling costs (IDC). Such accounts should be analyzed for geological and geophysical expenditures.
5. The tax treatment for domestic G&G expenditures was simplified with the enactment of amortization rules in IRC 167(h). For most oil and gas companies, amounts paid or incurred after August 8, 2005 with respect to domestic properties are amortized over a 24-month period under IRC section 167(h). The half-year convention specified in IRC 167(h)(2) results in the amortization deduction being spread over three tax years.
6. For certain "major integrated oil companies" defined in IRC 167(h)(5) the amortization period is extended to five years for expenses incurred after May 17, 2006 and seven years for expenses incurred after December 19, 2007. Examiners should note that the definition in IRC 167(h)(5) is unique, and could encompass the foreign refining operations for related entities. For example, a U.S. subsidiary could meet the definition of a major integrated oil company because of its foreign parent corporation's refining activities, even if the domestic sub doesn't meet the definition based on its activities. Thus, if a taxpayer amortizes all domestic G&G expenditures over 24 months, an examiner should consider requesting an explanatory statement regarding their classification under the definition. If any questions arise, the examiner should contact Local IRS Counsel.
7. IRC 167(h)(4) states that if properties are retired or abandoned before the end of the amortization period, amortization of the G&G expenditures continues and no immediate deduction is allowed for remaining amortizable amounts.

8. However, G&G expenditures incurred with respect to foreign properties are not subject to the amortization rules; such costs must be capitalized. The tax treatment of foreign G&G expenditures is discussed in Rev. Rul. 77-188, 1977-1 C.B. 76 as amplified by Rev. Rul. 83-105, 1983-2 C.B. 51. The assistance of an engineer will generally be needed in the examination of these expenditures. See *Exhibit 4.41.1-6* for a detailed discussion of the rules regarding foreign geological and geophysical expenditures.
9. Examiners may find that G&G expenditures are sometimes deducted as Intangible Drilling Costs (IDC). The definition of IDC in Treas. Reg. 1.612-4 does encompass certain "geologic works". See *Exhibit 4.41.1-5* where they are defined as "survey and seismic costs to locate a well site on leased property". Often, taxpayers will deduct an entire G&G survey as IDC when only a small portion relates to a specific well location. An IRS engineer may have to be consulted if that situation arises. There is no published guidance on whether the amortization rule of IRC 167(h) supersedes the deduction of "well-site G&G" as IDC. The examiner should contact Local IRS Counsel if this is a material issue.

4.41.1.2.2.3.3 (07-31-2002)

Legal, Travel, and Other Expenses

1. Legal expenses should be examined for charges for examination of abstracts, filing fees, quiet-title suits, and other items which should be capitalized as lease costs. General office expense or sundry expense accounts will often reveal charges applicable to lease acquisition costs.
2. Expenditures for travel incurred in the acquisition of leases must be capitalized and allocated to the leases involved. Analyze travel and other expenditures to determine those relative to the individuals instrumental in acquiring leases. Then relate these expenditures to leases comparing the locations and times of travel with the dates the leases were acquired.

4.41.1.2.2.3.4 (07-31-2002)

Minimum Royalty and Advance Royalty Payments

1. The original mineral owner (lessor) or a sublessor may contract for an advance royalty on transfer of the operating interest. Advance royalties result from lease provisions that require the operating interest owner to pay a specified royalty (a fixed amount or an amount based on royalties due on a specified production level) regardless of whether there is any oil or gas extracted within the period for which the royalty is due. Advance royalties also allow the lessee to apply any amount paid on account of oil and gas not extracted against royalties due on production in subsequent periods.

Example:

A lease with a primary term of 10 years requires a $\frac{1}{8}$ production royalty and also requires that royalties of \$100,000 be paid at the beginning of each of the first three years. If, in the first lease year the production royalties are \$20,000, the advanced royalty is \$80,000.

2. Generally, the payor of an advanced royalty can deduct the advanced royalty from gross income for the year in which the oil or gas on account of which it was paid is sold. See Treas. Reg. 1.612-3(b)(3). However, advanced royalties that result from a minimum royalty provision may, at the option of the payor, be deducted in the year paid or accrued.
3. For leases entered prior to October 29, 1976, this option to deduct in the year paid or accrued was available for all advance royalties. The option, however, is a one-time election for the taxpayer and, once chosen, cannot be changed.
4. A minimum royalty provision requires that a substantially uniform amount of royalties be paid at least annually either over the life of the lease or for a period of at least 20 years in the absence of mineral production requiring payment of aggregate royalties in a greater amount. The example in paragraph (1) above is not a minimum royalty. See Treas. Reg. 1.612-3(b)(3).
5. Depletion is generally allowable in the year the oil or gas is produced under IRC 613A. However, the Supreme Court decided in the consolidated cases of Fred L. Engle and Phillip D. Farmar dated January 10, 1984, that percentage depletion is allowable on oil and gas lease bonuses and advance royalty income. See *Commissioner v. Engle*, 464 US 206 (1984). The IRS stated in a news release dated May 18, 1984, that the depletion deduction could be taken in the year payment is received or accrued by the payee. Refer to Announcement 84-59, 1984-23 IRB 58. Refer to *IRM 4.41.1.3.9.3* for additional discussion of percentage depletion.
6. Examination of the lease record (which would include the royalty agreement), the journal entries recording minimum royalty transactions, and the related ledger accounts are proper steps to verify these transactions.

4.41.1.2.2.3.5 (10-01-2005)

Top Leasing

1. If a lease expires, any capitalized cost of the lease becomes a loss, even though the taxpayer may subsequently obtain a new lease on the property. If, prior to the expiration of a lease, a new lease is obtained covering the property, it is known as a top lease. In this case, the cost of the prior lease should not be allowed as a loss; and any bonus and other costs incurred in obtaining the renewal lease should be capitalized. In such event, the costs of both the old and new leases are included in the capital account of the property.
2. During the examination, look for top leasing transactions. Taxpayers frequently write off the cost of the original lease. Leases are carried under an identification number. The renewal may be noted by an "R" immediately after the lease number. Otherwise, compare the leases claimed as expirations with the new leases to see if the same property is involved. Another method is to ask the taxpayer if there are any top leases. Quite often when a top lease is taken, the new lease will have a completely different number than the old lease. To find leases which have been charged off even though top leased, it may be necessary to compare the locations of the abandonments with the company's current holdings on a company land map. (The land department will have one.) If the new lease is obtained after the date of expiration of the old lease, the loss may be allowable. Of course, facts and circumstances are vital elements in each case.

4.41.1.2.2.4 (07-31-2002)

Allocation Problems in New Acquisitions

1. An investment in minerals may be acquired by cash purchase, exchange of other property, services rendered, gift, inheritance, or liquidating dividends. In any transaction where different properties or assets are acquired, there may be the problem of allocation of the basis to the various properties or assets. In some contracts, the amount involving each separate property or asset may be stated. When stated at realistic values, this eliminates the problem of allocation. Some apparently simple transactions require complex allocations of purchase price to an extent that engineer assistance will be needed.

4.41.1.2.2.4.1 (07-31-2002)

Allocation of Geological and Geophysical Expenditures

1. The geological and geophysical expenditures incurred in an area must be allocated to the leases acquired and retained therein. This can best be illustrated by the following example. The A Oil Company, as a result of preliminary survey work, obtains an option or selective type lease covering 10,000 acres at a cost of \$4 per acre, or \$40,000. The lease is for a term of 5 years and 6 months. The terms of the lease provide that a minimum of 25 percent of the acreage must be selected before the expiration of 6 months, a bonus of \$10.00 per acre must be paid on the selected acreage, and a delay rental of \$2.00 per acre per annum be paid on acreage selected. The preliminary survey, core drilling, and other geological and geophysical costs amounted to \$24,000. Prior to the expiration of the first 6-month period, A Oil Company selected 2,500 acres under the lease for which they paid \$25,000 bonus.
2. The \$40,000 option cost, the \$24,000 geological and geophysical expenditures, if paid or incurred prior to the enactment of the Energy Tax Incentives Act of 2005 and the \$25,000 bonus should be capitalized as leasehold costs of the 2500 acres of land selected. Watch for this type of transaction. The taxpayer may claim an abandonment of 7,500 acres and a loss of 75 percent of the \$40,000 option cost plus all or part of the \$24,000 geological and geophysical costs paid. This abandonment will appear as a credit to the leasehold account and a debit in the Expired and Surrendered Leases Expense. The leasehold account may explain this credit as "released acreage" when actually the company never had a lease on the acreage, but only an option. The lease record usually identifies a lease by its terms, bonus, acreage, and other provisions, thereby making it possible to identify each lease acquired.

3. Remember that all of the geological and geophysical expenditures incurred in an area of interest are allocated to the acreage acquired and retained in the area. The acreage not retained is outside of the area considered to be favorable for development, regardless of the fact that an option was obtained as a protective measure during the study. See Rev. Rul. 77-188, 1977-1 CB 76.

4.41.1.2.2.4.2 (10-01-2005)

Allocation to Leasehold and Equipment Costs

1. An operator will sometimes purchase a block of leases from a broker in a lump sum purchase at the broker's purchase price plus a commission. Frequently, the broker's purchase price will be capitalized by the purchaser (operator) but the commission charged to expense. The entire cost to the operator should be capitalized and allocated to the lease acreage acquired in the purchase. You can identify this type of transaction by examining the commission expenses account and the purchase agreement. These two sources of identification are usually sufficient.
2. Look into the subsequent year to ascertain whether some undue tax advantage may have resulted from the allocation of the purchase price. An allocation of a disproportionate share of the purchase price may have been made to acreage considered undesirable and that would be released early, thus the retained acreage would have low leasehold costs.
3. When a producing property is purchased, the price paid must be allocated between leasehold and equipment. The cost basis is allocated between leasehold and equipment in proportion to their fair market value (FMV). Refer to Rev. Rul. 69-539, 1969-2 CB 141.
4. Upon finding that a taxpayer has acquired a group of properties for a lump sum, the agent should obtain from the taxpayer:
 - A. The allocation schedule and method
 - B. The engineer's report on which the purchase was based
5. The purchase of a group of producing properties, or a group of both producing and nonproducing properties, presents a complicated valuation problem. The best approach is to first allocate the total purchase price among the various properties. Although leasehold and equipment could be treated separately, at this point it is best to make allocations to each property. This helps keep values in perspective. Leasehold and equipment together (where applicable) are treated as a property unit. The reason for this is that most engineering appraisals, upon which purchases are based, value leasehold and equipment together. The valuation engineer projects future income and expenses of each property separately on an annual basis. Each future year's income is then discounted at the "going rate" to determine the present worth of all expected future net income to the property. The present worth of future income is then discounted a flat percentage to allow the purchaser a reasonable profit over and above interest on his/her investment. The projections include expected future capital investments as an expense and income from salvage of equipment as income. This type analysis necessarily includes income from sale of production and use of equipment in the same projection.
6. The projections made in this manner give a realistic value to the "package" of leasehold and equipment. Quite often the value of equipment depends on the value of the oil and gas which it will produce. Seldom will equipment salvage value be anywhere close to its replacement cost, but its utility value (if substantial amounts of oil and gas can be expected to be produced by it) can easily equal its replacement cost. If no oil or gas will be produced by the equipment, its only value is its salvage value. This is usually much less than replacement cost.
7. After the allocations have been made to each property, the property allocations will be divided between leasehold and equipment based on relative fair market values. In this allocation, normally equipment should not be valued at more than its replacement cost less depreciation or less than its net salvage value. Usually the value of the leasehold will have a bearing on the equipment value.
8. The most appropriate time for the IRS to make corrections to a taxpayer's allocations of a lump sum purchase price is in the year of purchase. The agent should be alert for acquisitions of groups of assets which may require allocations of purchase price. Quite often any type of incorrect allocation can ultimately allow the taxpayer to claim an incorrect tax advantage. This is true regardless of whether the amount allocated to a particular property or asset is too high or too low. The situations to watch for are whether allocations were made which would result in the cost being written off too rapidly through too great an allocation to nonproducing properties which were abandoned, and too great an amount of cost recovered through depreciation by reason of an excessive allocation of cost to depreciable property. A distortion could result in excessive abandonment losses, excessive depreciation, or percentage depletion where cost depletion should apply.
9. Allocation of purchase price may be a potential Whipsaw (aka Correlative Adjustments) issue. Refer to <http://irm.web.irs.gov/link.asp?link=4.10.7.4.9>. When a material amount is involved, every reasonable effort should be made to secure the return of both sides to the transaction to secure consistency of treatment. The buyer and seller will seldom value the property in a like manner.
10. The agent should be aware that Treas. Reg. 1.1245-1(a)(5) provides that, on the sale of IRC 1245 property and non-IRC 1245 property, if buyer and seller are adverse as to the allocation, any arm's-length agreement between buyer and seller will establish the allocation.
11. In all cases in which an agent has a substantial problem with respect to allocation among properties and between leasehold and equipment, the agent should request engineering assistance.
12. Refer to *IRM 4.41.1.4.1.3* for further discussion with emphasis on the seller.

4.41.1.2.3 (07-31-2002)

Complex Acquisition Arrangements

1. Nonproducing oil and gas leases, as well as producing properties, are acquired by oil operators through arrangements that are unique to the petroleum industry. These acquisition arrangements differ vastly from the normal purchase of properties. For purposes of this handbook, these unusual acquisition arrangements are referred to as complex acquisitions. Included in this category are acquisitions of property by drilling for an interest, performance of services for an interest, the use of production payments, "farm-ins," and the acquisition of government leases.

4.41.1.2.3.1 (10-01-2005)

Services Performed for Oil and Gas Property Interest

1. Frequently promoters, accountants, lawyers, geologists, operators, and others receive an interest in an oil and gas drilling venture in return for services rendered. These services may have been rendered in acquiring drilling prospects, evaluating leases, packaging the drilling program, or, in general, administrative services such as formation of partnerships, filing with Securities and Exchange Commission (SEC), and other functions.
2. It is a common practice for the promoter or sponsor of a drilling package to acquire part or all of the interest in the drilling venture in return for services. GCM 22730, 1941-1 CB 214, provided that the receipt of an interest in a drilling venture in return for capital and services furnished by a driller and equipment supplier was not taxable on receipt. This ruling provided for the "pool of capital" doctrine that is widely quoted in oil and gas tax law. The same reasoning has been extended to geologists, petroleum engineers, lease brokers, accountants, and lawyers who receive an interest in an oil or gas drilling venture in return for services rendered. This doctrine resulted from the court decision in *Palmer vs. Bender*, 287 U.S. 551 (1933); 1933-1 C.B. 235; 11 AFTR 1106; 3 USTC 1026.
3. The "pool of capital doctrine" is widely accepted by accountants and lawyers and is still quoted to justify the tax-free receipt of property for services. Subsequent changes in the tax laws, and subsequent court cases, have significantly limited the use of GCM 22730.
4. IRC 61 and 83, Treas. Reg. 1.61-1(a) and 1.721-1(b) provide that the receipt of property as payment for services rendered is taxable income to the extent of the fair market value of property received. IRC 83 was enacted by the 1969 Tax Reform Act. It provides rules for the time and manner that property will be valued for this purpose. Case law that supports the taxation of property received for services rendered is *James A. Lewis Engineering Inc. v. Commissioner*, 339 F.2d 706 (5th Cir. 1964); 15 AFTR 2d 9; 65-1 USTC 9122; *Diamond v. Commissioner*, 56 T.C. 530 (1971); aff'd, 492 F.2d 286 (7th Cir. 1974); 33 AFTR 2d 852; 74-1 USTC 9309; and *U.S. v. Frazell*, 335 F.2d 487 (5th Cir. 1964); 14 AFTR 2d 5378; 64-2 USTC 9684; cert. denied, 380 U.S. 961 (1963). Refer to IRC 636(a).

5. Agents who are examining oil and gas partnerships and drilling ventures should carefully analyze the partnership agreement, joint venture agreement, and prospectus to determine if the promoter or sponsor of the venture is receiving a property interest in the form of an interest in a joint venture or partnership in return for services rendered. This is a very complex area of tax law; therefore, it is essential that the facts are carefully analyzed and documented. The issue should not be proposed without extensive research. In most cases, an examiner should discuss the issue with the group manager before attempting to fully develop the issue due to the time usually required by this issue.
6. An additional problem that will be encountered is that the status of GCM 22730 is unclear at this time. It has not been revoked although it seems to have been partially superseded by the 1954 Code, case law, and the 1969 Tax Reform Act. Technical advice is recommended when this issue is considered and the adjustment is substantial.
7. Some guidance with respect to this problem has been issued in Rev. Rul. 83-46, 1983-1 CB 16, which holds that an attorney, a corporation, and a corporate employee each have income under IRC 83 when each receives an overriding royalty in an oil and gas property for services in connection with the acquisition and/or development of the property. Rev. Proc. 93-27 1993-2 CB 343 deals with the receipt of a "partnership profits interest" for the provision of services to or for the benefit of a partnership by a person in a partner capacity or in anticipation of being a partner. In certain circumstances the Service will not treat the receipt of such an interest as a taxable event for the partner or partnership. Rev. Proc. 2001-43, 2001-2 CB 191 further clarifies Rev. Proc. 93-27. See also *Campbell v. Commissioner*, 943 F.2d 815 (8th Cir. 1991).
8. While the pool of capital doctrine is still viable in specific factual circumstances, it does not equate to a special exemption from IRC 83 for the oil and gas industry. Generally, for the pool of capital doctrine to apply, all of the following must occur:
 - A. The contributor of services must receive a share of production, and the share of production is marked by an assignment of an economic interest in return for the contribution of services.
 - B. The services contributed may not in effect be a substitution of capital.
 - C. The contribution must perform a function necessary to bring the property into production or augment the pool of capital already invested in the oil and gas in place.
 - D. The contribution must be specific to the property in which the economic interest is earned.
 - E. The contribution must be definite and determinable.
 - F. The contributor must look only to the economic interest for the possibility of profit.

4.41.1.2.3.2 (07-31-2002)

Drilling Free Well for Interest in a Lease

1. Drilling contractors will sometimes drill a well on an oil and gas lease in return for an interest in the lease. For instance, if a promoter has acquired a lease on 3,000 acres and lacks the necessary funds to drill a test well, an offer of a 6/8 interest in the lease in return for drilling a well may ensue. The drilling contractor will incur 100 percent of the drilling cost in return for a 75 percent interest in the 3,000 acre lease. Since the driller is entitled to only 75 percent of the working interest oil, 25 percent of drilling costs and equipment costs as leasehold cost must be capitalized. See Treas. Reg. 1.612-4(a). The promoter cannot deduct any cost of drilling or deduct any depreciation because no expenses were incurred.

4.41.1.2.3.3 (10-01-2005)

Drilling as Consideration for Property Outside of the Drill Site

1. Oil operators sometimes agree to drill a well on another owner's property in return for 100 percent of the working interest in the drilling site. For additional background on this subject, refer to the discussions of "farm-in" and "carried interest" found in *IRM 4.41.1.2.3.8* and Rev. Rul. 77-176, 1977-1 CB 77.
2. Rev. Rul. 77-176, 1977-1 CB 77, provides examples of the tax treatment to be afforded to the carrying party (operator) and the carried party (lease owner). Generally, the ruling states that the driller will be entitled to deduct 100 percent of the intangible drilling and development costs (IDC) if the arrangement is a true carried interest. Refer to *IRM 4.41.1.2.4.8.4* references. The driller will, however, receive income to the extent of the value of the property outside of the drill site. Examiners should carefully inspect the legal instruments and lease assignments where "carried interests" are present to determine if acreage outside of the drilling site is conveyed as consideration of drilling. See Rev. Rul. 77-176, 1977-1 CB 77 for instructions.
3. The "carried party," in situations described above, also incurs a taxable event. The transferor will have a gain or loss on the transfer of property other than the drilling site. The consideration deemed received is the "fair market value" of the property transferred excluding the drilling site.

4.41.1.2.3.4 (07-31-2002)

Drilling Site Location as Consideration for a Net Profits Interest

1. A net profits interest is considered to be an overriding royalty payable out of the working interest income. See IRC 614 and Rev. Rul. 73-541, 1973-2 CB 206. A conveyance of a drilling site in return for a net profits interest is similar to a situation in which an operator conveys a working interest in a lease and retains an overriding royalty interest. The results would essentially be the same on nonproducing properties. The operator who drills the well would be entitled to deduct 100 percent of the IDC, and the transferor would be considered to have merely retained an overriding royalty interest.
2. If producing properties are conveyed in exchange for a retained net profits interest, the transferor would generally be subject to the recapture provisions of the tax laws in regard to investment tax credits and depreciation, if a gain results. Refer to IRC 50 and IRC 1245.

4.41.1.2.3.5 (12-03-2013)

Acquisition of Property by a Production Payment

1. A production payment is a share of the minerals produced from a lease, free of the cost of production, that *inter alia* terminates when a specified sum of money has been realized. Production payments may be reserved by a lessor or carved out by the owner of the working interest. Refer to Treas. Reg. 1.636-3(a)(1) and (2) and *IRM 4.41.1.3.1.4* for further definition.
2. Prior to the Tax Reform Act of 1969, oil and gas production payments were treated as economic interests in oil and gas. In acquisitions of oil and gas leases, production payments were frequently retained by the seller as a financing tool. The purchaser of a lease was not required to report the income accruing to the production payment retained by the previous lease owner. Thus, it can be seen that oil and gas property could be acquired and paid for out of production that was not taxable to the purchaser. A common practice in the acquisition of oil and gas properties prior to passage of the 1969 Tax Reform Act was to use a production payment in so-called "ABC" transactions. However, since the 1969 Tax Reform Act, IRC 636 treats mineral production payments as loans with one exception. Therefore, the acquisition of a property burdened by a production payment is usually similar to the purchase of a property encumbered by a mortgage.
3. Agents should realize, however, that carved-out production payments pledged for development are excepted from treatment as loans by IRC 636.

4.41.1.2.3.6 (07-31-2002)

Acquisition of Government Oil and Gas Leases

1. The United States Department of the Interior announces blocks of acreage available for lease by competitive bid under the Outer Continental Shelf Lands Act of a specific date.
2. Generally, two contiguous leases acquired on the same day, whether by single or separate documents from the same assignor, would be treated as one property. Refer to IRC 614(j) and Treas. Reg. 1.614-1(a)(3). However, government leases are an exception to the rule above; refer to Rev. Rul. 68-566, 1968-2, CB 281. The government leases are not considered to be acquired simultaneously, even though executed on the same date, because the granting of any one lease by competitive bidding is independent of the granting on other leases.

3. Offshore government oil and gas leases may be defined as blocks containing 5,000 acres identified by numbers and includes the seabed and subsoil of the submarine areas adjacent to the territorial waters of the United States over which the United States has exclusive rights, in accordance with international law, with respect to the exploration and exploitation of natural resources.
4. In many of the Western states of the U.S., the Government owns the mineral rights. These mineral rights are administered by the Bureau of Land Management (BLM) <http://www.blm.gov/wo/st/en.html> of the Department of the Interior. Except for lands located within a known geologic structure of a producing oil or gas field, BLM is required by law to lease these minerals on a noncompetitive basis to the first qualified applicant. Although some of the minerals are not particularly valuable for oil and gas exploration, some of the minerals are quite attractive.
5. In an area where there is little or no current oil and gas exploration activity, a person may acquire leases merely by application and paying the filing fees and first year's rental.
6. The BLM leases the Government tracts which are on proven structures (and are, therefore, not wildcat) to the highest responsible bidder on a competitive bidding basis.
7. For some years, the competition has been extremely keen for wildcat leases in the attractive areas of New Mexico, Wyoming, and Colorado. Many persons have wanted to be the first qualified applicant when specific tracts become open for leasing. The reason for this is that the leases had a ready market at values many times the amount that BLM will accept for them.
8. The situation described in paragraph (7) prompted the BLM to devise the following plan for determining who was the first qualified applicant for any tract.
 - A. The BLM announces the tracts by size, legal description, and date they are to be available for leasing.
 - B. Interested persons are allowed to file an application to lease any or all tracts, but each separately described lease requires a separately filed lease application.
 - C. A nominal nonrefundable filing fee of \$10 is required for each filing application.
 - D. A person may file only one application for any one tract.
 - E. On the prescribed date, a lottery-type drawing is held by the BLM.
 - F. The "winner" is then awarded the lease and must then pay the first year's rental to the BLM. All \$10 filing fees are retained by the BLM.
9. The drawings have all the characteristics of a lottery.
 - A. A fee is charged for entry in the "drawing."
 - B. The winner is awarded a property far in excess of the entry fee plus delay rentals.
 - C. The fee is nonrefundable.
 - D. The actual drawing is held, utilizing card tickets very similar to lottery tickets.
10. Because of the resemblance to lotteries, it is believed by some people that the successful bidder is actually being awarded a prize and has income to the extent of the difference between the value of the lease and the filing fee. Rev. Rul. 67-135, 1967-1 CB 20 settled this question by ruling that the successful applicant has not won a prize and no taxable event has occurred.
11. Prior to 1956, it had been the Service's position that any cash payment paid by the lessee to the lessor upon granting of an oil and gas lease was a capital investment in the property and not deductible as a business expense. This was true even if the payment was termed a rental and was the same amount for each successive year of the lease. Rev. Rul. 56-252, 1956-1 CB 210, superseded by Rev. Rul. 80-49, 1980-1 CB 127, reversed this position as it applied to Government leases. After the issuance of this revenue ruling (with one exception), all "rentals" paid on Government leases have been treated as business expense, currently deductible.
12. Rev. Rul. 69-467, 1969-2 CB 142, held that, under the following facts, the first-year rentals paid for a Government lease were a capital investment in an overriding royalty:
 - A. The taxpayer filed an application for a Government lease and paid the first-year rental.
 - B. In the same year, the taxpayer assigned rights under the application to a third party for cash and a further agreement that, if the lease was issued, the third party would pay an additional sum and allow the taxpayer to retain an overriding royalty.
13. Fees paid by successful applicants for participation in bidding for noncompetitive Government leases are capital investments. See IRC 611 and Rev. Rul. 67-141, 1967-1 CB 153.

4.41.1.2.3.7 (07-31-2002)

Overhead Costs of Oil Company Departments

1. Certain departmental overhead costs should be allocated to the cost of acquiring oil and gas leasehold properties. This includes both developed and undeveloped properties. For a discussion of the various items that should be considered for capitalization in property acquisitions, refer to *IRM 4.41.1.3.2.2*.

4.41.1.2.3.8 (07-31-2002)

Farm-In and Farm-Out

1. The use of the terms "farm-in" and "farm-out" are found in connection with the transfer of property in a "sharing arrangement." A "farm-out" and "farm-in" occurs when a leasehold interest in an oil and gas property, along with the burden of developing the property, is transferred from one working interest owner to another and the transferee agrees to assume the development burden in return for the leasehold interest in the property. The transferor will usually retain some type of interest in the property, normally an overriding royalty interest. A farm-out by *Taxpayer A*, the transferor, is a farm-in to *Taxpayer B*, the transferee.
2. The acquisition or disposition of the interest in property by a farm-in or farm-out will not normally result in a taxable event, except for that property which is outside the "drill site" as described in Rev. Rul. 77-176, 1977-1 CB 77. Refer to *IRM 4.41.1.2.3.3* for the discussion regarding those transfers.
3. The arrangements and details regarding the transfer of any property should be reviewed in detail to ascertain the taxability of the transaction.

4.41.1.2.4 (10-01-2005)

Intangible Drilling and Development Cost (IDC)

1. In the case of oil and gas wells, a taxpayer has an option to treat intangible drilling and development costs as either capital expenditures, under IRC 263(a), or as expenses as provided in IRC 263(c) and Treas. Reg. 1.612-4. In the event that the taxpayer has elected to capitalize such costs, they become part of the depletable investment recoverable through the depletion deduction Treas. Reg. 1.612-4(b)(1). Refer to *United States v. Dakota-Montana Oil Co.*, 288 U.S. 459 (1933); 12 AFTR 18; 3 USTC 1067. If a taxpayer has elected to capitalize IDC, Treas. Reg. 1.612-4(b)(4) provides an election to charge to expense the IDC with respect to nonproductive wells.

4.41.1.2.4.1 (07-31-2002)

Definition of IDC

1. Intangible drilling and development costs (IDC) is a phrase peculiar to the law of oil and gas taxation. It describes all expenditures made for wages, fuel, repairs, hauling, supplies, and other items incident to and necessary for the drilling of wells and the preparation of wells for the production of oil and gas. Treas. Reg. 1.612-4(2) list costs which are specifically designated as costs which come within the option to charge to capital or expense. Treas. Reg. 1.612-5(c)(1) and Rev. Rul. 70-414, 1970-2 CB 132, list costs which are not subject to the option.

4.41.1.2.4.2 (07-31-2002)

Working Interest

1. IRC 263(c) provides that intangible drilling and development costs incurred in the development of oil and gas properties may, at the option of the taxpayer, be chargeable to capital or to expense. However, to qualify, the taxpayer must be one who holds a working or operating interest (see Treas. Reg. 1.612-4) in the well during the complete payout period. For a definition of "economic interest," see Treas. Reg. 1.611-1(b). For a definition of "operating interest," see Treas. Reg. 1.614-2(b). For a definition of "complete payout period," see Rev. Rul. 70-336, 1970-1 CB 145 and Rev. Rul. 80-109, 1980-1 CB 129.

4.41.1.2.4.3 (10-01-2005)

Election Regarding Intangible Drilling and Development Costs

1. IRC 263(c) provides that Intangible Drilling and Development Costs (IDC) incurred by an operator in the development of oil and gas properties may, at the taxpayer's option, be chargeable to capital or expense. For this purpose, "operator" is defined as one who holds a working or operating interest in any tract or parcel of land either as a fee owner or under a lease or any other form of contract granting working or operating rights. The option granted by Treas. Reg. 1.612-4 to charge IDC to expense may be exercised by claiming IDC as a deduction on the taxpayer's return for the first taxable year in which the taxpayer pays or incurs such costs. If the taxpayer fails to deduct such costs as expenses on such return, the taxpayer shall be deemed to have elected to recover such costs through depletion to the extent they are not represented by physical property. The election, once made, is irrevocable. Refer to *Exhibit 4.41.1-4*.
2. Taxpayers that initially elected to expense IDC have the opportunity to make a secondary election to capitalize and amortize, under IRC 59(e), all or part of the IDC. For each tax year such taxpayers may elect to capitalize any portion of the IDC and amortize the cost on a straight line basis over 60 months. The amount subject to the IRC 59(e) election will not be treated as a tax preference item in determining the taxpayer's Alternative Minimum Tax (AMT). The amount that a taxpayer elects to amortize for a particular taxable year is generally irrevocable. Examiners should review Treas. Reg. 1.59-1 for the rules regarding the election.
3. Refer to *Exhibit 4.41.1-5* for a classification of expenditures in acquisition, development, and operation of oil and gas leases.

4.41.1.2.4.3.1 (07-31-2002)

Integrated Oil Companies

1. In the case of a corporation which is an integrated oil company, IRC 291(b) provides that the amount allowable as a deduction under IRC 263(c) is reduced by 30 percent. This provision applies to IDC paid or incurred after 1986. The amount not allowable (30 percent) as a current expense is allowable as a deduction pro-rated over a 60-month period beginning with the month in which the costs are paid or incurred, and is not to be taken into account for purposes of determining depletion under IRC 611. Refer to IRC 291(b)(2)(5).
2. For purposes of IRC 291(b) an "integrated oil company," with respect to any taxable year, means any holder of an economic interest with respect to crude oil who is not an independent producer. An independent producer is a person who is allowed to compute percentage depletion under the provisions of IRC 613A(c).

4.41.1.2.4.3.2 (10-01-2005)

IDC Incurred Outside of the United States (Foreign IDC)

1. There are special rules for IDC incurred outside the United States. IRC 263(i) requires IDC paid or incurred outside the United States to be capitalized. It must be capitalized to the depletable basis of the property or amortized on a straight line basis over 10 years. The capitalized IDC which is attributable to installation of casing, derricks, and other physical property must be recovered through depreciation. See Rev. Rul. 87-134, 1987-2 CB 69.
2. There is a special exception for IDC incurred or paid for certain North Sea operations. It provides that the foreign IDC capitalization rules do not apply to the IDC which was incurred by a United States company pursuant to a minority interest in a license for Netherlands or United Kingdom North Sea development. The interest must have been acquired prior to 1986. The U.S. company is still required to capitalize 20 percent of such IDC incurred. The requirement to capitalize foreign IDC does not apply to dry holes or nonproductive wells. The "North Sea IDC Transition Rule" issue was decoordinated in 2009. Refer to <http://lmsb.irs.gov/hq/c/memos/Miller/2009-071309.asp>.
3. An issue has arisen where IDC is subject to an election to be deducted currently under IRC 263(c), and where a portion of IDC amortized under IRC 291(b) was paid or incurred with regard to a nonproductive well.
 - A. Can a taxpayer file an amended return and deduct the unamortized IDC in the year paid or incurred for wells that prove to be nonproductive after the close of the taxable year?
 - B. The Service's view is that an amended return may be filed for that year deducting the unamortized IDC for the wells that prove to be unproductive after the close of the taxable year. If the taxpayer previously deducted the unamortized IDC in the year the nonproductive well was plugged and abandoned, an amended return must be filed taking into income the amount that was deducted.
4. Refer to Rev. Rul. 93-26, 1993 CB 50 for how to account for the unamortized amounts when the underlying property is sold or the taxpayer ceases to be an integrated producer.

4.41.1.2.4.4 (12-03-2013)

Distinction between IDC and Nonproductive Well Costs

1. Examiners should be aware that there are some important differences in the tax treatment of Intangible Drilling Costs (IDC) and "nonproductive well costs". While the treatment of IDC under the IRC is generally favorable for taxpayers, the treatment of nonproductive well costs is even more favorable. Nonproductive well costs are the IDC incurred in the drilling of a nonproductive well. The code, regulations, and revenue rulings do not use the term "dry hole" but it is somewhat analogous. Treas. Reg. 1.1254-1(b)(1)(vi) defines a nonproductive well as:

"[a] well that does not produce oil or gas in commercial quantities, including a well that is drilled for the purpose of ascertaining the existence, location, or extent of an oil or gas reservoir (e.g., a delineation well). The term nonproductive well does not include an injection well (other than an injection well drilled as part of a project that does not result in production in commercial quantities)".

2. The production of oil and gas in "commercial quantities" is not defined by the code, regulations or revenue rulings. A brief mention in the Committee Report on P.L. 94-455 (Tax Reform Act of 1976) indicates that commercial quantities are relative to the cost of drilling the well. As explained in Rev. Rul. 84-128, 1984-2 CB 15, a well that is merely temporarily shut in does not constitute a nonproductive well for purposes of computing the AMT tax preference for IDC under IRC 57(a)(2). Similarly, a well should not be treated as nonproductive if it is still producing oil and gas, or is capable of being restored to economic production, even if it has not yet generated enough income to offset drilling and equipment costs.
3. For purposes of this section of the IRM the term "successful well" will be used to describe a well that is not a nonproductive well. Differences in tax treatment of IDC on successful wells and nonproductive wells costs include:
 - Taxpayers normally elect to currently deduct IDC incurred in the U.S. For those that elect to capitalize such IDC, Treas. Reg. 1.612-4(b)(4) provides a secondary election whereby IDC associated with nonproductive wells can still be currently deducted.
 - IRC 263(i) requires that IDC incurred by U.S. taxpayers in drilling a successful well outside the United States must be capitalized and recovered via either cost depletion (IRC 611) or via amortization over 10 years. In contrast, nonproductive well costs incurred by U.S. taxpayers for foreign wells are currently deductible.
 - IRC 291(b) requires integrated oil companies to capitalize 30 percent of the IDC incurred in drilling successful wells in the U.S. over 60 months. In contrast, 100 percent of nonproductive well costs incurred by integrated oil companies are currently deductible. See the legislative history of IRC 291 discussed in Technical Advice Memorandum 9418002.

- IDC that is currently deductible under IRC 263(c) or amortized during the tax year under IRC 291 forms the basis of computing an AMT tax preference item under IRC 57(a)(2). However, the costs of drilling a nonproductive well are not included in the AMT preference item. Refer to IRC 57(b)(2)(B)(i) .
 - IRC 1254 provides that IDC is subject to recapture upon the sale of the underlying mineral property. However, Treas. Reg 1.1254-1(b)(1)(vi) generally provides that recapture does not apply to costs associated with drilling a nonproductive well
4. Without conclusive evidence that a well is nonproductive as of the date of filing its original tax return, a taxpayer should assume that IDC incurred during the year was related to a successful well. If the well is later determined to be nonproductive the taxpayer may file an amended return to treat the IDC as nonproductive for that taxable year rather than the year in which the well was determined to be nonproductive. See the discussion of legislative history from the Tax Reform Act of 1976 that is cited in IRS Technical Advice Memorandum 9418002.
5. Both IDC on successful wells and nonproductive well costs are normally reported as an Other Deduction on Line 26 of a corporate income tax return. Examiners may find that they are combined and reported only as "Drilling Costs" . Examiners should request separate lists of the two types of costs by well (preferably in electronic format) so they can be analyzed. Examiners should also look for unusually large figures and also for figures that suggest an estimated amount was deducted (e.g., exactly \$1,250,000).

4.41.1.2.4.5 (12-03-2013)

Plug and Abandonment Versus Temporary Abandonment

1. The tax treatment of drilling costs is dependent to a large degree upon operational decisions made at the conclusion of the drilling phase. When the drilling of a well reaches total depth the operator must decide how to proceed. Information will first be gathered from well "logging" tools (sensors) to help determine certain characteristics of the geologic layers and any fluids contained within. Other tools that can obtain small cores and fluid samples from prospective reservoirs may also be lowered into the well and then retrieved. On rare occasions the operator will attempt to produce the well to verify that a commercial rate of oil and gas can be achieved. Based on the results, the operator will place the well into one of the following conditions:
- A. **Plugged and Abandoned ("P&A")** . Cement will be placed within the well in a number of intervals and a metal plate welded to the top near the ground level. For offshore wells the final step in the "P&A" process is to sever the well a few feet below the mud line. The operator will file a "P&A" or "Dry Hole" report with the appropriate regulatory agency.
 - B. **Temporarily Abandoned** . The operator will leave the well in a state where it can be placed into production by future operations, utilized for the drilling of a deeper section or sidetracks, or even "P&A'd" . The drilling rig may install the final string of casing in the well before leaving the drill site. Future operations, such as installing the tubing and perforating the well, may be performed by a less expensive "completion rig" . The operator will file a Temporarily Abandoned or Idle Well report with the appropriate regulatory agency.
 - C. **Shut-in** . The final string of casing and the well tubing is installed. The well is perforated and the christmas tree is installed. A retrievable plug or check-valve may be set in the tubing just below the christmas tree for safety purposes, but the well is otherwise ready to produce. Shut-in status may occur when there is not yet a pipeline or tank battery for the well to flow into. The operator will file a Shut-in or Idle Well report with the appropriate regulatory agency.
 - D. **Producing** . The well is completed and production to the pipeline or tank battery has been established. The operator will file a Completed Well report with the appropriate regulatory agency.
2. Since there are numerous regulatory agencies, the title of the well status reports and the information that must accompany them when submitted varies. However, when submitting a report for any status other than "P&A" , geologic formations that appear to be hydrocarbon bearing must usually be identified. This information can be useful in disputing that a well is "nonproductive" or that the underlying mineral property is worthless and should be written off as an abandonment loss.
3. **Tax Considerations** - When a well has been drilled and then placed into either temporarily abandoned or shut-in status, the drilling costs should generally be treated as IDC. Examiners often find that wells that are temporarily abandoned are improperly treated as nonproductive wells or improperly written off as abandonment losses. When a well is plugged and abandoned immediately after drilling, the well is clearly nonproductive, and drilling costs can be treated as such. When the "P&A" operation occurs some time after the completion of drilling operations, a review of the facts will be required to determine if previously incurred IDC was associated with the drilling of a successful well. The assistance of an IRS engineer may be necessary. The cost of the "P&A" operation itself could be deducted as either nonproductive well costs or operating expenses of the property where the well is located. Refer to *IRM 4.41.1.3.2.4.1*.

4.41.1.2.4.6 (07-31-2002)

Capital

1. The option with respect to IDC does not apply to expenditures by which the taxpayer acquires tangible property ordinarily considered as having a salvage value. If the taxpayer fails to deduct costs qualifying as intangible drilling costs as expenses on the taxpayer's return for the first taxable year in which the taxpayer pays or incurs such costs, the taxpayer is deemed to have elected to recover such costs through depletion to the extent that they are not represented by physical property, and through depreciation to the extent that they are represented by physical property. Normally, taxpayers will elect to deduct IDC currently.

4.41.1.2.4.7 (07-31-2002)

Year of Deduction

1. The timing of a tax deduction for many taxpayers is an important factor in the planning of a good tax program. The deductions for IDC could be a major item in this tax planning. Like other deductible expenses, the deductions for IDC depend on the taxpayer making the election to deduct the expenses, method of accounting, drilling contract provisions, and many other factors.

4.41.1.2.4.7.1 (07-31-2002)

Prepaid Expenses

1. For taxpayers using the cash basis method of accounting, IDC is deductible in the year paid, under certain conditions, although the work is performed in the following year. Refer to *Pauley v. United States* , 63-1 USTC 9280; 11 AFTR 2d 955.

Example:

Taxpayer A owns 100 percent of the working interest in an oil and gas lease and enters into a drilling agreement with *Taxpayer B* for the drilling of a well on *Taxpayer A's* property. The drilling agreement provides that *Taxpayer B* will drill the well to the desired depth for \$500,000 and will begin the work as soon as *Taxpayer B* has a rig available, but no later than January the next year. The agreement, executed in December, requires *Taxpayer A* to pay the \$500,000 fixed price upon execution of the contract in order for *Taxpayer B* to have sufficient funds to drill the well. *Taxpayer A* is on the cash basis of accounting and paid *Taxpayer B* as provided in the agreement on December 29, 1999.

2. The Government's position regarding the deduction of prepaid IDC by a cash basis taxpayer is set out in Rev. Rul. 71-252, 1971-1, CB 146 and Rev. Rul. 71-579, 1971-2, CB 225. The Tax Court sustained parts of the IRS position in *Keller v. Commissioner* , 79 TC 7 (1982). Ordinarily, the prepaid expense is deductible if:

- A. The prepayment is made for a bona fide business purpose.
- B. The prepayment does not substantially distort income.
- C. The drilling contract requires a prepayment of the agreed amount. The prepayment must not be a mere deposit.
- D. The prepayment covers the full 100 percent working interest.
- E. The actual drilling of the well was begun in the first part of the next year.

F. Some well site work was done prior to the year end.

3. In the above example, *Taxpayer A* is entitled to deduct the prepaid amount in 1999 since *Taxpayer A* has met all the conditions set forth in the revenue rulings.
4. The examining agent should be aware that, generally, when there are several working interest owners of the property, the operator of the property is the person that makes the contacts with the drilling company and enters into the drilling contract for the drilling of the well. The drilling contractor will require the prepayment of the agreed amounts from the operator. It is, therefore, unlikely that a drilling contract would require a prepayment from any interest owners other than the operator. The prepayment to the operator by a nonoperator working interest owner does not satisfy the requirements for a deductible prepayment unless the operator was required to make a prepayment in accordance with the rules set out above. The method of accounting used by the operator generally controls the deductibility of any amount to the working interest owners. See *IRM 4.41.1.2.4.7.4*. The drilling contract and prepayment agreement should always be examined to learn the facts regarding every material prepayment requirement.
5. The above discussion and revenue rulings apply only to the cash basis taxpayer. The deduction to the accrual basis taxpayer is controlled by the general rules regarding the accrual of any type of expense including the economic performance requirements of IRC IRC 461(h).

4.41.1.2.4.7.2 (07-31-2002) **Method of Accounting**

1. The method of accounting used by the individual taxpayer, as well as by the operators of working interests, is very important in determining the year of deduction of intangible drilling and development expenses. Because the cash basis method of accounting gives the taxpayer more control over the timing of a deduction, most taxpayers use this method of accounting.
2. **Cash Method** — The cash method of accounting in the oil and gas business is no different than in any other business. The expenses are deductible when incurred and paid, and the income is taxable when received. The general rules of *IRM 4.41.1.2.4.7.4* should be kept in mind when there is an operator and other working interest owners that have joint billings involved.
3. **Accrual Method** — The accrual method of accounting in the oil and gas business is similar to any other business. The expenses are deductible when all events have occurred to fix the liability and income is taxable when received or earned. If the taxpayer owns drilling equipment and drills its own wells, the IDC is deductible when incurred. If the taxpayer has contracted for the drilling of the wells, the provisions of the drilling contract will fix the liability for the accrual of the expense deduction. Special attention should be given to the contract provisions in order to determine the proper accruals of any year end.
4. **Completed Contract Method** — The use of the completed contract method of accounting for the deduction of IDC can not be used by the accrual basis taxpayer to postpone the deduction until a succeeding year. The cost must be deducted in the year paid or incurred, depending on the taxpayer's general method of accounting.

4.41.1.2.4.7.3 (07-31-2002) **Contract Provisions**

1. **Turnkey** — The Turnkey drilling contract is an agreement that calls for the drilling contractor to drill a well to a specified depth and furnish certain equipment and supplies for a preagreed lump-sum price. Since this type of contract does not separate the tangible equipment cost from the intangible drilling cost, the agent should make sure that the leasehold and equipment costs are properly capitalized. A common problem is for the taxpayer to deduct the entire percentage of the Turnkey price without regard to the capital items included in the contract. To the accrual basis taxpayer, the accrual of the expense should only be made when all the events to fix the liability have been satisfied including the economic performance requirements of IRC IRC 461(h). There are several variations of the general Turnkey contract which might call for different stages of completion and equipping of the well. The contract provisions should be examined in order to determine the proper tax treatment of the lump sum expenditure.
2. **Footage** — The Footage contract provides for the drilling contractor to perform specific services to drill the hole at a specified price per foot. This type of contract usually provides that the contractor will also be paid an hourly or daily work rate for any other service performed during the drilling of the well. If the well is a productive well, additional cost will be incurred for the completion and equipment on the well. These costs will be in addition to the footage drilling price. The agent should make sure that all tangible equipment costs are capitalized and all IDC identified properly.
3. **Day Work** — The Day Work drilling contract generally provides for the drilling contractor to drill a well and be paid for services based on an agreed rate per day. This type of contract is usually used by a drilling contractor where problems with the geological formations may be encountered and in unfamiliar areas. This type of drilling contract avoids the risks to the driller inherent in Turnkey and Footage contracts. The loss of drilling mud, high gas pressure blowouts, "fishing jobs," or unusually hard formations are examples of problems that can cause delays and increase the cost to the contractor. The lease operators will be charged for "third-party" costs, such as, drilling mud, drilling bits, fuel costs, water and site preparation cost, in addition to the day work rate charged by the drilling contractor. The agent should look at these drilling contracts and agreements to make sure the proper costs and charges are deducted as IDC.

4.41.1.2.4.7.4 (07-31-2002) **Agency Relationships**

1. It is common practice in the oil and gas industry for joint owners of working interests to designate one owner as the "operator" of their properties. For this purpose "operator" is considered to be the person who bears the most responsibility for the management and day to day activities of drilling, completing and operating the wells. Normally, the operator performs duties in accordance with an operating agreement that all joint owners have endorsed. The operator manages the drilling, completing, and operating efforts on the property, pays all expenses, and bills joint owners for their share of the expenses. The operator is usually from one to six months behind in billing to the several joint owners. An agency relationship exists between the operator and the nonoperator, and the timing of the deduction to the nonoperator is an important item.
2. The tax accounting for the cash basis nonoperator will be controlled by the operator's payment of the expense items. The IDC and operating expenses should be deducted in the year paid or incurred even though they may be reimbursed in a later year. The operator must have incurred and paid the expense before the nonoperator's deduction is allowable. The nonoperator has not paid until payment is made by the operator. See *McAdams v. Commissioner*, 52-2 USTC 9373, 198 F. 2d 54 (5th Cir. 1952).
3. The deductions of the accrual-basis nonoperator will be allowable only if the accrual-basis operator has an expense that is properly accrued, or if the cash basis operator has actually paid the expense.
4. The agent should be aware of this problem area, and the legal relationship between the parties should be determined for a proper timing of the expense deductions. The examination of the operator's and nonoperator's returns should include the examination of the year-end expenses and, where material errors are found, corrected.

4.41.1.2.4.8 (07-31-2002) **Who Gets the Deduction**

1. The right to deduct IDC is available only to the taxpayers who own the working interest or operating rights in the properties on which the expenses are incurred. See Treas. Reg. 1.612-4(a). If a well is drilled for the acquisition of a fractional working interest in the property, a deduction for the intangibles is allowed only for the cost attributable to the fractional interest acquired. Any IDC attributable to the working interest owned by someone else is a capital cost and must be added to the leasehold basis of the interest acquired. See Rev. Rul. 70-657, 1970-2 CB 70.

4.41.1.2.4.8.1 (07-31-2002) **Operator Drilling Own Well**

1. Many times the owner-operator of an oil and gas lease owns drilling equipment as well as the oil and gas wells being drilled. If the taxpayer has made the election to expense the intangible drilling and development cost, this cost incurred or paid may be deducted. The timing of the deduction depends on the method of accounting. These expenses include all direct costs, indirect costs, and the current depreciation of the equipment. Refer to *Commissioner v. Idaho Power Co.*, 418 US1 (1974).
2. The scope of the examination of an owner-operator drilling its own wells should be extended to the operating expense accounts to ensure that all costs attributable to the drilling of the wells are properly classified as intangible drilling costs. The proper classification is necessary because of the computations of tax preference items, depletion, and any gain or loss on the subsequent disposition of the property. If the taxpayer owns something less than 100 percent of the working interest and pays all the cost of drilling the well, only the intangible costs attributable to the working interest percentage owned is deductible and the balance is capitalized to the leasehold basis.

3. If the taxpayer owns only a fractional interest in the working interest and drills the well on the property for all the working interest owners, the taxpayer should realize a profit or loss on the drilling of the well separate from the IDC deduction.

Example:

Taxpayer A, B, and C each own $\frac{1}{3}$ of the working interest of an oil and gas lease. *Taxpayer A* also owns the necessary drilling equipment to drill the well. *Taxpayer A* agrees to drill the well to 8,000 feet for \$360,000. Each owner agrees to pay $\frac{1}{3}$ of the price. *Taxpayer A* drilled the well as agreed at a total cost of \$300,000. *Taxpayer A* has an IDC deduction of \$100,000 and an ordinary profit from the drilling of the well of \$40,000. *Taxpayers B and C* each have an IDC deduction of \$120,000.

4. In this example, notice the factual differences from the preceding example in that *Taxpayers B and C* are paying for IDC and an interest in a lease. Assume that *Taxpayer A* owns 100 percent of the working interest in an oil and gas lease. *Taxpayer A* approaches *Taxpayers B and C* with a deal and transfers to each of them a $\frac{1}{3}$ interest in the property with the agreement to drill an 8,000-foot well on the property for a "turnkey" price of \$150,000 each. *Taxpayer A* had acquired the property several years before for \$9,000. The well was drilled by *Taxpayer A* at a total cost of \$300,000. (A price of \$45 per foot is the "going" price for drilling in this area to this depth.) *Taxpayer A* has made a sale of $\frac{2}{3}$ leasehold interest and entered into a drilling contract with *Taxpayers B and C*. *Taxpayer A* realizes a gain on the sale of the leasehold of \$54,000, a profit on the drilling agreement of \$40,000, and has an IDC deduction of \$100,000. *Taxpayers B and C* have a leasehold cost of \$30,000 each and an IDC deduction of \$120,000 each. See Rev. Rul. Rev. Rul. 73-211, 1973-1 CB 303.
5. Assume the same facts as in the above example except that the payment for the transfer of the $\frac{2}{3}$ leasehold interest to *Taxpayer B* and *Taxpayer C* was conditioned on the drilling of a producing well. Refer to Rev. Rul. 75-304, 1975-2 CB 94. Since the IDC deductions are available to the working interest owners only, *Taxpayer A* is entitled to deduct the entire \$300,000 cost of drilling the well. *Taxpayer A*, therefore, has a gain on the sale of the leasehold of \$294,000, of which \$200,000 is ordinary income in accordance with IRC 1254 and the balance of \$94,000 is controlled by IRC 1231. This is assuming that *Taxpayer A* is not in the trade or business of selling oil and gas leases, and the oil and gas lease was not held for sale to customers. *Taxpayers B and C* have no deductions for intangible drilling and development costs, but each must capitalize the \$150,000 to their leasehold basis.
6. The examination of taxpayers that have drilling and development arrangements, such as those mentioned above, should include the examination of the assignment of the property, letter agreements, operating agreements, and drilling contracts. Before making an examination of an oil and gas operator's IDC, the examiner should be familiar with what qualifies as IDC and carried interest arrangements. The Audit Technique Guide to the Oil and Gas Industry [http://www.irs.gov/Businesses/Small-Businesses-&Self-Employed/Audit-Techniques-Guides-\(ATGs\)](http://www.irs.gov/Businesses/Small-Businesses-&Self-Employed/Audit-Techniques-Guides-(ATGs)) is a good starting point, and it identifies 11 revenue rulings that address IDC in the context of sharing arrangements. Rev. Rul. 75-446, 1975-2 CB 95 and Rev. Rul. 80-109, 1980-1 CB 129 are additional rulings that deal specifically with carried interest arrangements. The textbook used for Oil and Gas Unit II training should also be consulted. http://lmsb.irs.gov/hq/mf/2/training/cpa/lmsb_regular_training/11036_oil_gas_phase_II_2005.asp

4.41.1.2.4.8.2 (10-01-2005)

Partnerships

1. Very often the partnership form of doing business is used in the oil and gas industry since it is a convenient means of bringing a large number of widely scattered investors or owners into one joint business undertaking. During the development period of oil and gas properties, the IDC may be allocated to the partners in accordance with the partnership agreement. IRC 704(b) and Treas. Reg. 1.704-1(b) provide that this allocation of income, expenses, gains, losses, or credits can be made in accordance with this agreement if such allocation has "substantial economic effect." For a complete explanation of "substantial economic effect" see Treas. Reg. 1.704-1(b) (in its entirety), and court cases *Orrisch v. Commissioner*, 55 TC 395 (1970), and *Allison v. U.S.*, 83-1 USTC 9241 (Fed. Cir. March 7, 1983).
2. The election to expense the IDC must be made by the partnership the first year the partnership incurs IDC. If the partnership agreement so provides, subject to the provisions of Treas. Reg. 1.704-1(b), it is permissible to allocate the partnership expenses, such as IDC, to the partner or partners contributing the funds for the expenditures.
3. In the examination of oil and gas partnerships, it is important to first verify that a true partnership exists. Once verified, it is very important to always inspect the partnership agreement for provisions regarding allocations of income, expenses, gains, losses, and credits. If there is a change in partners or the ratio of allocations of income, expenses, gains, losses, or credits during the partnership year, refer to Rev. Rul. 77-310 and Rev. Rul. 77-311, 1977-2 CB 217 and 218 to prevent the retroactive allocations of these items. Special care should be taken to make sure that all items are allocated in accordance with the sharing ratio in effect at the time the income, expenses, gains, losses, or credits were earned or incurred.

4.41.1.2.4.8.3 (07-31-2002)

Free Well Drilled for Fractional Interest

1. Many times an interest in an oil and gas lease will be transferred to another person in order to get a well drilled on the property at no cost to the transferor.

Example:

Taxpayer A owns 100 percent of the working interest in an oil and gas lease and agrees to assign to *Taxpayer B* 50 percent of the working interest in the property if *Taxpayer B* will drill and equip a well on the property at *Taxpayer B's* expense.

2. This arrangement is known as a "free well" arrangement and the transfer of the property is sometimes called a "farm-out" to *Taxpayer B* from *Taxpayer A*. *Taxpayer A* does not create a taxable event on the transfer of the property to *Taxpayer B*. Since *Taxpayer B* owns only 50 percent of the working interest in the property, *Taxpayer B* can only deduct 50 percent of the IDC of drilling the well. The balance of the cost must be capitalized to the leasehold basis. Likewise *Taxpayer B* can depreciate only 50 percent of the tangible equipment cost, with the balance of the cost to be capitalized to *Taxpayer B's* leasehold basis. If the well is not a producer, *Taxpayer B* still must capitalize 50 percent of the IDC to the leasehold basis. *Taxpayer B* may deduct the leasehold cost as a loss in the year the property is abandoned, surrendered, released, or otherwise proven worthless. See Treas. Reg. 1.612-4j and Rev. Rul. 70-657, 1970-2 CB 70.
3. In the examination of both *Taxpayer A* and *B* above, all instruments regarding the "free well" arrangement should be inspected. This should include the assignment of the property, letter arrangements regarding the drilling of the well, and operating agreement. These instruments should give all the details of the arrangement so that the examiner can determine the proper tax treatment. Special care should be given to the examination of *Taxpayer B* to make sure the proper IDC has been deducted, the proper leasehold cost has been capitalized, and the investment tax credit has only been claimed on the amount capitalized to the depreciable asset account.

4.41.1.2.4.8.4 (10-01-2005)

Carried Interest

1. The term "carried interest" generally refers to an arrangement where one co-owner of an operating interest (the "carrying party") incurs an obligation to pay all of the cost to develop and operate a mineral property, in exchange for a right to recoup this investment out of the proceeds of first production from the property. After the investment is repaid, any subsequent production is split between the co-owner(s). The co-owner(s) not obligated to pay for the development and operation hold a carried interest in the mineral property until the carrying party's initial investment is repaid.
2. A typical carried interest arrangement is as follows:

Example:

Taxpayer A owns 100 percent of the working interest in an oil and gas lease and is interested in having a well drilled on it.

- *Taxpayer A* assigns to *Taxpayer B* the entire working interest in the property, and *Taxpayer B* agrees to drill, complete, and equip a well free of all cost to *Taxpayer A*.
- *Taxpayer B* is to retain 100 percent of the working interest until the entire cost is recovered (including drilling, completing, equipping, and operating the well) out of the production from the property. After *Taxpayer B* recovers cost, 50 percent of the working interest in the property is to be transferred back to *Taxpayer A*, and the working interest ownership is to be owned equally by each thereafter.
- Normally, *Taxpayer A* and *B* will elect out of the provisions of Subchapter K following Treas. Reg. 3930 and 3948 or Treas. Reg. 1.761-2(a).
- The arrangement above is the most common carried interest. *Taxpayer A* realizes no gain or loss on the transfer of the property. Drilling a productive well would only

increase the value of the property interest to be returned to *Taxpayer A*. The basis in *Taxpayer A*'s residual interest would take the basis of the entire property prior to the transfer. After *Taxpayer B* has recovered cost in accordance with the carried interest arrangement and transfers back to *Taxpayer A* 50 percent of the working interest, *Taxpayer A* realizes no taxable event because of the transfer. *Taxpayer A* has no basis in the depreciable equipment and, therefore, has no depreciation or investment tax credit on the value of the equipment acquired.

- Since *Taxpayer B* owns all the working interest and operating rights to the property during the drilling of the well and is entitled to all the income from the entire working interest during the complete payout period of the well, *Taxpayer B* is entitled to deduct all the IDC of drilling the well. *Taxpayer B* is required to capitalize all equipment cost and should claim the investment tax credits on the qualified equipment purchases. *Taxpayer B* will report all income and expenses from the property during the entire payout period. After payout, *Taxpayer B* must capitalize to *Taxpayer B*'s leasehold basis the unrecovered equipment cost attributable to the half interest which reverts to *Taxpayer A*. *Taxpayer B* must also recapture the investment tax credit attributable to the equipment transferred to *Taxpayer A*. See Rev. Rul. 71-207, 1971-1 CB 160.

3. The examination of *Taxpayers A* and *B* above should include an inspection of the lease agreement, carried interest agreement, operating agreement, and accounting for the carried interest payout. The examiner should make sure that *Taxpayer B* has the full working interest in the lease during the complete payout period before allowing *Taxpayer B* to deduct the entire IDC. Rev. Rul. 71-207 provides an example of a complete payout. *Taxpayer B* must also report all the income and expenses from the property. Normally, both *Taxpayer A* and *B* will "monitor" the profits from the property for payout purposes; this payout amount can be compared to the tax profit for comparison purposes. Any deviation from the usual carried interest arrangements should be inspected closely since failure to qualify may result in the disallowance of part of the IDC.
4. Another type of carried interest arrangement that is different from the above and has a different tax treatment can be illustrated as follows:

Example:

Taxpayer A owns 100 percent of the working interest in an oil and gas lease and is interested in having a well drilled on the property.

- *Taxpayer A* assigns to *Taxpayer B* the full working interest in the property and *Taxpayer B* agrees to drill, complete, and equip a well on the property free of all cost to *Taxpayer A*.
- *Taxpayer B* is to retain the full working interest until *Taxpayer B* has recovered \$400,000 out of the net profits from the property. At recovery, 50 percent of the working interest in the property reverts back to *Taxpayer A*.
- *Taxpayer B* knows that it will cost \$500,000 to drill and complete the well and another \$100,000 to equip the well. In order for *Taxpayer B* to be entitled to deduct all the IDC, *Taxpayer B* must own the entire working interest or operating rights in the well during both the drilling period and the payout period.
- Since *Taxpayer B* will not own the entire operating rights during the entire payout period, *Taxpayer B* is not entitled to deduct all the IDC.
- *Taxpayer B* must capitalize to the leasehold basis the IDC and depreciable equipment cost applicable to *Taxpayer A*. *Taxpayer B* must capitalize \$250,000 (\$500,000 x 50 percent) of the IDC and \$50,000 (\$100,000 x 50 percent) of the equipment cost to leasehold basis.
- *Taxpayer B* must also report all the income and expenses from the property during the \$400,000 payout period.
- *Taxpayer A* has no taxable event because of the transfer. See Rev. Rul. 70-336, 1970-1 CB 145, Rev. Rul. 71-206, 1971-1 CB 105 and Rev. Rul. 80-109, 1980-1 CB 129.

5. In order to know all the facts of the carried interest arrangements, the lease assignments, carried interest agreements, operating agreements, and any letter agreements must be studied.
6. There are several types of carried interest arrangements that are used in the oil and gas business. They have different provisions to suit the taxpayer's individual needs and desires. The agent should study the instruments and then do the research needed to apply the law based on the facts of each case. Refer to *IRM 4.41.1.4.4* for further discussion.

4.41.1.2.4.8.5 (12-03-2013)

"Cash and Carry" Arrangements

1. The emergence of "shale plays" in the U.S. has led to arrangements between parties that vary from the traditional farm-in and free-well arrangements. Generally known as "cash and carry" arrangements, an illustration of the implementation of a basic one is provided below.
2. An explanation of the tax treatment of an operating interest in oil and gas property received for a drilling well is provided in Rev. Rul. 77-176, 1977-1 CB 77:

"[G]CM 22730, 1941-1 C.B. 214 provides, in part, that when drillers or equipment suppliers and investors contribute materials and services in connection with the development of a mineral property in exchange for an economic interest in such property, the receipt of the economic interest does not result in realization of income. The contributors are viewed as not performing services for compensation, but as acquiring capital interests through an undertaking to make a contribution to the pool of capital. To come within the holding of GCM 22730, the economic interest acquired must be in the same property to the development of which the materials and services are contributed. With respect to the transferor of the economic interest, GCM 22730 states that such transferor has parted with no capital interest but has merely given the transferee (driller, equipment supplier, or investor) a right to share in production in consideration of an investment made."

Example:

OilCoA owns 100 percent working interest (WI) in Lease1 which has good potential for development by a single well. OilCoA's depletable basis is \$1000x. For economic and operational control purposes, OilCoA desires an outside party to drill and equip a well on Lease1 at its own cost to earn a 40 percent WI in Lease1. The estimated cost to drill and equip a well is \$3000x.

OilCoA decides to accept an offer made by OilCoB whereby it earns a 40 percent WI in Lease1 by paying \$300x free and clear to OilCoA in addition to paying the cost to drill a well and equip that well, if successful. The agreement requires the \$300x to be paid to OilCoA upon execution of the agreement. The payment is not refundable in the event the well is nonproductive (i.e., a dry hole is drilled). The agreement also provides that OilCoB must commence drilling by a certain date or else it loses its right to drill and earn the 40 percent WI. There is no payout provision, the effect of which is that immediately after the well is drilled and equipped (or P&A'd if dry) each company's fractional WI in Lease1 takes effect. The parties agree to elect out of the partnership provisions of Subchapter K of the Code. OilCoB fulfills its obligation by drilling a well. It incurs \$2500x of IDC and \$500x of lease and well equipment cost. OilCoA assigns a 40 percent WI to OilCoB.

Consequently, OilCoB in the above example made a contribution to the pool of capital (the reservoir beneath Lease1) by paying the cost to drill and equip the well. The receipt of a 40 percent WI is not compensation for services, and does not constitute a taxable event. In accordance with Treas. Reg. 1.612-4(a), OilCoB can deduct only 40 percent of the IDC it incurred (\$1000x = \$2500x x 40 percent). Sixty percent of OilCoB's expenditure for IDC becomes part of its depletable basis (\$1500x = \$2500x x 60 percent). The regulation similarly affects OilCoB's expenditure of \$500 for equipment. Only 40 percent can be recovered via depreciation (\$200x = \$500x x 40 percent) and 60 percent is added to OilCoB's depletable basis (\$300x = \$500x x 60 percent). Finally, since OilCoB's payment of \$300x free and clear to OilCoA was not used for items necessary for drilling or for acquisition of equipment, the \$300x is added to OilCoB's depletable basis.

For OilCoA, its transfer of a 40 percent WI also does not result in a taxable transaction. OilCoA has parted with no capital interest, rather its 60 percent retained WI is with respect to a larger pool of capital (Lease1 and OilCoB's capital). Consequently, OilCoA transfers its \$1000x basis in Lease1 to its retained 60 percent WI.

Upon execution of the agreement, the \$300x received by OilCoA is in the nature of an option payment by OilCoB to have the right to acquire a working interest in Lease1. OilCoA should report the \$300x as proceeds from a capital transaction if and when OilCoB earns its 40 percent WI pursuant to the agreement. Since OilCoA must transfer its entire basis in Lease1 to its retained 60 percent WI, it has no basis to offset the \$300x. Had the agreement terminated without OilCoB earning any interest in Lease1 (e.g., by failure to drill the well), OilCoA would report the \$300x as ordinary income (not subject to depletion) as payment on a lapsed option. Refer to Rev. Rul. 57-40, 1957-1 CB 266, citing *Virginia Iron Coal & Coke Co v. Commissioner*, CA-4, 38-2 USTC 9572, 99 F2d 919. Cert. denied, 307 US 630.

4.41.1.2.4.8.6 (07-31-2002)

Free Well Drilled for Nonoperating Interest

1. Drilling for an interest in the property many times includes the receipt of an interest in property other than the property being drilled. Rev. Rul. 77-176, 1977-1 CB 77 provides the income tax treatment for the taxpayers in this type of drilling "deal."

Example:

Taxpayer A owns the entire working interest in a 640-acre oil and gas lease. *Taxpayer A* is willing to transfer to *Taxpayer B* the entire working interest in a 40-acre drill site and 50 percent of working interest in the remaining 600 acres if *Taxpayer B* will drill and equip a well on the 40-acre site free of all costs to *Taxpayer A* and allow *Taxpayer A* to retain a $\frac{1}{16}$ overriding royalty interest in the 40-acre tract. After *Taxpayer B* successfully drilled and equipped the well as a producer, *Taxpayer A* assigned the working interest to *Taxpayer B* as agreed.

- *Taxpayer A* has a taxable event on the transfer of the property outside the 40-acre drill site to *Taxpayer B*. *Taxpayer A* is treated as having sold 50 percent of working interest to *Taxpayer B* at its fair market value and having paid the cash proceeds to *Taxpayer B* as consideration for the drilling of the well on the 40 acre drill site. The nature of the gain or loss on the sale will depend on the length of time the property was held by *Taxpayer A* and if it was held primarily for sale to customers in the course of *Taxpayer A*'s trade or business. "A" must capitalize to *Taxpayer A*'s $\frac{1}{16}$ overriding royalty interest the fair market value of the 50 percent of the working interest sold. "A" has two separate properties, the $\frac{1}{16}$ overriding royalty on the 40 acres and 50 percent of the working interest on the 600 acres.

- *Taxpayer B* has an entirely different tax consequence. Since *Taxpayer B* received the entire working interest in the 40-acre drill site, *Taxpayer B* can deduct all the IDC. *Taxpayer B* is also entitled to all the depreciation on the capitalized tangible equipment. *Taxpayer B* has two separate properties on the assignment of the 40-acre and the 600-acre oil and gas leases. Since the assignment of $\frac{1}{2}$ of the working interest in the 600 acres outside the drill site is a transfer of property to which no development contribution was made, the drilling done by *Taxpayer B* on the drill site does not represent a capital investment in the development of the non-drill site property. Therefore, the 50 percent of the working interest in the 600 acres represents gross income to *Taxpayer B* to the extent of its fair market value at the date of transfer.

4.41.1.2.4.8.7 (07-31-2002)

Bottom-Hole and Dry-Hole Contributions

1. In the examination of intangible drilling and development expenses, certain unusual arrangements between working interest owners can be found.

Example:

Taxpayer A owns the entire working interest in an oil and gas lease and wants to drill a well on owned unproven property. The information *Taxpayer A* obtains from drilling the geologic formations can be very useful to lease owner *Taxpayer B* who owns the oil and gas lease adjoining *Taxpayer A*. *Taxpayer B* agrees to pay \$30,000 to *Taxpayer A* toward the cost of the drilling of a well on *Taxpayer A*'s property to a total depth of 8,000 feet. *Taxpayer B* is willing to do this because the information obtained from drilling the test well conveys productive potential of *Taxpayer B*'s lease acreage.

- When the total depth of 8,000 feet is reached and *Taxpayer B* makes the payment to *Taxpayer A*, *Taxpayer B* has made a bottom-hole contribution. *Taxpayer A* will be required to report the \$30,000 as ordinary income. The receipt of the \$30,000 bottom-hole contribution will not affect *Taxpayer A*'s IDC or investment in equipment. One hundred percent of *Taxpayer A*'s IDC will either be capitalized or expensed according to *Taxpayer A*'s election under IRC 263(c). One hundred percent of *Taxpayer A*'s investment in lease and well equipment must be capitalized. *Taxpayer B* must treat the payment of the \$30,000 as a cost of geological and geophysical information. See IRC 167(h) and IRM 4.41.1.2.2.3.2.

2. In the example above, the \$30,000 was payable by *Taxpayer B* to *Taxpayer A* regardless of the results of drilling the well, assuming that a depth of 8,000 feet was reached. However, frequently *Taxpayer B* will agree to pay *Taxpayer A* the \$30,000 only if the well is plugged and abandoned as a dry hole. The tax treatment of bottom-hole contributions and dry-hole contributions is exactly the same.

4.41.1.2.4.9 (12-03-2013)

Offshore Development (Marine Offshore Exploration)

1. Oil and gas reservoirs under bays, gulfs, and seas are just like those under land surfaces. Sometimes these reservoirs are extensions of those already proven on shore. Irregularities in subsurface strata exist in such forms as salt plugs or domes, buried reefs, faults, folds, anticlines, or other geologic formations related to the shifting of the earth's crust. These irregularities or anomalies may indicate the presence of oil or gas deposits. There must be a source-type rock formation, a reservoir-type rock with pore structure able to contain hydrocarbons, and a barrier-type rock which will trap and retain hydrocarbons migrating from their source bed.
2. Refer to IRM 4.41.1.2.3.6 for acquisition of offshore government oil and gas leases.
3. Offshore development requires structures, equipment, facilities, and wells that are specially designed to operate in a marine environment.

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