



Oil & Gas Audit Technique Guide

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The taxpayer names and addresses shown in this publication are hypothetical.

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I. Overview

A. Introduction

- (1) This guide 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 1: Research Material Available, 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 10: Items To Consider During Examination for preparing Forms 4318, 4764, 4764-B and 886-A or IMS Lead sheets, Exam Plan or other issue examination forms.

B. 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 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 Audit Technique Guide (ATG), examination techniques are interspersed with discussion of the legal aspects of the 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 1: Research Material Available, Oil and Gas Taxation 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 Internal Revenue Manual (IRM). In the event of any inconsistencies between these guidelines and the basic text of the IRM, 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 Checkpoint Learning online courses on Oil and Gas Taxation prior to beginning an examination of an oil and gas company.

C. Requesting Assistance from Specialty Groups and Subject Matter Experts and Specialist

- (1) During an examination of an oil and gas company, an examiner will likely require assistance from one or more subject matter experts (SME) or specialists. The examiner should involve these employees early in the examination process as they will greatly assist in identifying, planning, and developing the issues. See to [IRM 4.46.3, LB&I Examination Process - Planning the Examination](#).
- (2) A good practice is to speak with a Petroleum Industry SME. That person will have broad knowledge of the industry and will be familiar with many of the issues you might encounter. The IRS Virtual Library contains a list of the current [Petroleum Industry SMEs](#). Examiners can also submit a formal request for their services by using the [Request Tracker](#) and selecting “Industry Practice Network” in the drop-down box at the top.
- (3) For domestic issues, the most detailed technical tax material is maintained by SMEs who reside in Practice Networks that are focused on broad types of issues, such as Deductible and Capital Expenditures and Energy and Investment Tax Credits. The Virtual Library contains a [list of Practice Networks](#) and a cross reference to the Internal Revenue Code (IRC) sections for which they maintain expertise and resources. Once an examiner has determined the appropriate Practice Network and reviewed resources on its site, the SMEs can be contacted informally. Alternatively, formal assistance can be requested by

using the [Request Tracker](#) and selecting the appropriate Practice Network in the drop-down box at the top.

- (4) An examiner may also need assistance from one or more specialty examiners (specialists). Prime examples include a fuel Excise Tax Agent or an IRS Petroleum Engineer. Use the [SRS - \(Specialist Referral System\)](#) to request their services. See also [IRM 4.46.3.2.6, Specialist Referral System \(SRS\)](#), and [IRM 4.46.3.2.6.1, Specialist Referrals](#).
- **IRS Engineer:** Referrals should be made during the early stages of each examination when significant and complex engineering issues are noted on the return.
 - **Computer Audit Specialist:** During 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.
 - **Cross Border Activities (CBA) Representative (formerly referred to as an International Examiner):** Many oil and gas companies operate in countries other than the United States. Referral to a CBA representative should be made early in the examination when it is ascertained that the taxpayer is engaged in business outside the United States either directly or through related, controlled, or controlling affiliates. Examiners should closely review [IRM 4.46.3.2.6.2, International Referrals - Supporting Documentation and Informal Assistance](#), and use the [SRS - \(Specialist Referral System\)](#) to request the services of a CBA representative. See also [IRM 4.46.3.2.6, Specialist Referral System \(SRS\)](#) and [IRM 4.46.3.2.6.1, Specialist Referrals](#). 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.
 - **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.
 - **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.

- **Tax Exempt and Government Entities (TEGE) Specialists:** Contact TEGE Agent Managers 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 TEGE 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 [TEGE Knowledge Management Portal](#) and [How to Make a Referral to TEGE](#). See [TEGE Connect](#) and [IRM 4.70.6.4](#), Referral Procedures, for additional TEGE referral information.

D. State Regulation of Oil and Gas Production

- (1) Oil and gas exploration and production is closely supervised and regulated by 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, 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, etc.
- (3) Most states impose a severance tax on oil and gas production but the rates and manner in which they are applied are not uniform. 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.

E. 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.

F. 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 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:
 - foreign tax credit
 - IRC § 199 (It should be noted, this section was repealed by Tax Cuts and Jobs Act (TCJA), Pub. L. 115-97, 131 Stat 2054, but remains relevant for any years under exam prior to its repeal.)
 - research credit
 - transfer pricing

F.1. 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:
 - **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.

- **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 to move significant quantities of crude oil, 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 transport 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.
- **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 ranges from privately owned firms that operate in a limited region to multinational corporations with activities, employees, and customers around the world.

II. Acquisitions

A. Introduction

- (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 Section II.C, Lease and Leasehold Costs and Section II.D, Complex Acquisition Arrangements.
- (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 verifying the cost of a property. The cost (basis) of the real property interest is recovered through depletion. IRC § 611. This cost also provides the basis for the computation of gain or loss on the sale of all or part of such property. IRC § 612. The depletion allowed for oil and gas property under IRC § 611 is computed using percentage depletion under IRC § 613, as limited by IRC § 613A, which provides depletion deductions based on a specified

percentage of gross income from the property. For a further discussion of depletion, see Section VII – Oil and Gas Well Depletion. If the property is producing, the cost or basis of the associated equipment is recovered through depreciation. IRC § 611(a) & (c). 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. See Exhibit 3: Useful Examination Techniques - Lease Acquisition Costs.

B. Acquisition Transactions

- (1) The examination of an oil and gas producer (operator) is difficult due to 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 are 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.

B.1. 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:

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.

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.

B.2. Landowner and Fee Royalty Owner

- (1) A landowner generally owns what is known as a “fee interest,” which comprises 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 (*i.e.*, 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 treated as advance royalties for income tax purposes. *Anderson v. Helvering*, 310 US 404, 409 (1940); 24 AFTR 967; 40-1 USTC 553 (“Cash bonus payments, when included in a royalty lease, are regarded as advance royalties and are given the same tax consequences.”) Cost recovery of bonus payments are limited to cost depletion. 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. Treas. Reg. § 1.612-3(c)(2). The delay rental is not an advance payment for oil but is in the nature of rent paid for the privilege of deferring development. Treas. Reg. § 1.612-3(c)(1). Section II.C.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 thereunder, provided that percentage depletion is greater than cost depletion. Treas. Reg. § 1.611-1(a); IRC §§ 613(a) and 613A(c) & (d)(1). This will usually be the case when the landowner simultaneously acquires the surface and subsurface interests in a tract of land, but the subsurface (or mineral rights) have little, if any, value.
- (5) If the lease expires, terminates, or is abandoned before any income has been derived from the extraction of minerals, the depletion previously allowed against bonus income must be restored to income in the year the lease terminates. 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 must compute cost depletion on these payments. IRC § 613A(d)(5). Restoration to income of bonus depletion is not 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 IRC § 1231. If the sale of the property meets the requirements of 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:

Seller's cost included a stipulated amount for mineral rights.

Seller's basis was the result of an estate tax valuation in which minerals and surface were valued separately.

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) Basis is relevant 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 may indicate either unreported income from delay rental or a lapsed lease which may require restoration of bonus depletion by the lessor.

B.3. 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:

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 also* Treas. Reg. § 1.636-3(a)(2) for situations where a royalty will be treated as a production payment.

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 2: Division of the Production From Oil and Gas Property 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.

B.4. 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 $1/8^{\text{th}}$ of the production from the property, however, the amount can vary. Royalty rates of $1/6^{\text{th}}$, $1/16^{\text{th}}$, and $1/4^{\text{th}}$ are also common. Assuming that a $1/8^{\text{th}}$ royalty interest is retained, the right to receive the remaining $7/8^{\text{th}}$ of production is generally conveyed to the lessee oil company in consideration for a cash bonus and its obligation to develop the property in accordance with the lease agreement that both parties sign. Another type of royalty is known as an override, which is an interest reserved or carved out of the working interest held by the lessee oil company, 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.

B.5. 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 $1/8$) 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. A Royalty and Fee Land Record contains information related to 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 sold, while retaining a smaller portion as its own investment. A fraction of the cost corresponding to the fractional interest is retained. Thus, if a dealer purchases 1/16 royalty (1/2 of the landowner's 1/8) for \$8,000 and sells a 3/64 interest (3/4 royalty), the basis for the portion sold is \$6,000. The basis of the 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) Geological and geophysical expenses paid or incurred by independent producers shall be allowed as a deduction over the 24-month period beginning on the date the expense was paid or incurred. IRC § 167(h)(1). Amounts paid or incurred by major integrated oil companies are amortizable over 7 years under IRC § 167(h)(5)(A) using a mandatory half-year convention under IRC § 167(h)(2).
- (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, general office, and other expenses.

B.6. Oil and Gas Leasing Contracts

- (1) The interests of an investor or operator in mineral deposits as well as the right 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 should 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:

Principal parties.

Date - Determines the precedence of documents.

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.

Granting clause - Specifies what the lessor has granted, and the consideration paid.

Royalty clause - Sets out the principal consideration, aside from any cash bonus, for the property owner to sign the agreement. The landowner's royalty (usually 1/8 of gross production) is free and clear of any drilling or operating expenses.

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.

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.

Special considerations - Additional clauses may be inserted in a lease agreement to describe the rights and duties of the parties more fully, 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.

C. 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 as described in the lease. A lease usually provides for:

- Cash (lease bonus) payable to the lessor upon the execution of the lease and approval of the title.
 - Specified term of years, usually from three to ten years.
 - Delay rental for each expiring year during which the lessee has not commenced drilling operations.
 - Lease cancellation if lessee does not pay delay rental by the due date.
 - How oil and gas produced will be divided between the lessor and the lessee.
 - 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 delay 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 1/8 interest in the minerals may sign a lease instrument which is 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.

C.1. Installment Bonus Payments

- (1) When examining the lease record for properties acquired during the year, agents should 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.

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. The amount of these payments would be found in the lease rental expense account, but the nature of the payments are determined by examination of the provisions of the lease itself.

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.

A production payment retained in a leasing transaction is treated as if it were a bonus granted by the lessee to the lessor paid in installments. See § IRC 636(c); Treas. Reg. § 1.636-2(a). A production payment is taxable as oil income when received, not when the lease is made by the lessor.

C.2. 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, the lease agreement will either expire or provide for the payment of a sum of money for the lessee to retain the lease without developing the property. These payments are known as “delay rental” payments and are made to grant 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 bonuses, 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. 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, 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); TAM 9602002 (January 12, 1996).

C.3. 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 operator 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 should be supported by records.
- (3) The subsidiary ledger for nonproducing leases is generally maintained in accordance with geographic location by state, subdivided by county, 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 lease is kept. Some companies make direct charges to the subsidiary nonproducing lease record, 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) To determine whether 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 appear in these accounts on each lease and should be capitalized are the lease bonus, abstract costs, abstract examination fee,

filing fee, delay rentals, and travel expense. In addition, any commissions paid for obtaining the lease should be included and capitalized. 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 5: Classification of Expenditures in Acquisition, Development, and Operation of Oil and Gas Leases provides examples of how to classify expenditures in acquisition, development, and operation of oil and gas leases.

C.4. Capitalization of Non-direct Costs under IRC 263 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:

IRC § 263 and the regulations thereunder.

- IRC § 263A (a/k/a Uniform Capitalization Rules (UNICAP)) and the regulations thereunder.

- (2) Amounts that are capitalized under §§ 263 and 263A must be taken into account through a charge to capital account or basis, or in the case of property that is inventory in the hands of the taxpayer, through inclusion in inventory costs. Capitalized costs may not be deducted as a current expense. Rather, capitalized costs are recovered through depreciation, depletion, amortization, cost of goods sold, or by an adjustment to basis at the time the property is placed in service, sold, used or otherwise disposed of by the taxpayer.
- (3) **IRC § 263(a)**. Section 263(a) generally requires capitalization of (i) amounts paid out for new buildings or for permanent improvements or betterments made to increase the value of any property or estate or (ii) amount expended in restoring property or in making good the exhaustion for which an allowance is or has been made.

IRC § 263(c) provides an exception to the general rule requiring capitalization by allowing a taxpayer to make an election to deduct as expenses Intangible Drilling and Developments Costs (IDC). See also IRC § 263A(c)(3). IDC are expenditures made by an operator for wages, fuel, repairs, hauling, supplies, etc., incident to and necessary for the drilling of and preparation of wells of the

production of oil or gas and that do not have a salvage value. Treas. Reg. § 1.612-4(a); See *also* the listed examples. However, IRC § 263(c) requires an examination of each cost to determine whether it is, in whole or in part, related to IDC. An item that is not wholly related to IDC must be allocated and apportioned and the portion not relating to IDC must be capitalized. Treas. Reg. § 1.613-5(a); See *also* TAM 8640006 (June 19, 1986) (analyzing allocation and apportionment of costs in detail.) which cited several court cases. The following excerpts from TAM 864006 indicate the capitalization of IDC is a determination made based on all 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 IRC § 263(c).
- 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 involve 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.

- (4) **Treas. Reg. §§ 1.263(a)-1 through 1.263(a)-3.** Sections 1.263(a)-1 through 3 of the Treasury Regulations provide guidance on the application of IRC §§ 162(a) and 263(a) to tangible property. Generally, these regulations require that taxpayers capitalize amounts paid to acquire, produce, or improve tangible property.

Treas. Reg. § 1.263(a)-1 provides the general rules for capitalization of costs, including a de minimis safe harbor election whereby a taxpayer may elect not to capitalize costs of certain tangible property if the costs of such property fall beneath certain dollar thresholds and the taxpayer adheres to certain financial accounting policies. See § 1.263(a)-1(f).

Treas. Reg. § 1.263(a)-2 provides specific rules for the acquisition and production of tangible property, including rules for the inclusion of certain transaction costs in the basis of acquired property.

Examiners will find that the regulations under IRC § 263 often cross reference and require coordination with the regulations under IRC § 263A. For example, Treas. Reg. § 1.263(a)-2(f)(2)(iv) states that amounts paid for employee

compensation (within the meaning of Treas. Reg. § 1.263(a)-4(c)(4)(ii)) and overhead are treated as amounts that do not facilitate the acquisition of real or personal property. However, the 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.

Example 4 of Treas. Reg. § 1.263(a)-2(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).

Treas. Reg. § 1.263(a)-3 provides the rules for determining whether amounts incurred for tangible property must be capitalized as improvements to such property. Under § 1.263(a)-3(d) amounts are characterized as improvements if they are for betterments to the unit of property (“UOP”), restore the UOP; or adapt the UOP to a new or different use. To apply these criteria, a taxpayer must first identify the UOP that is the subject of this analysis. Treas. Reg. § 1.263(a)-3(e), provides rules for identifying the UOP, building structure, or building systems to which the improvement analysis must be applied.

- Examiners who focus on refinery improvements and turnaround costs should review the guidelines for unit of property for “Plant Property” that are found in Treas. Reg. § 1.263(a)-3(e)(3)(ii) and the examples for “Plant Property” found under Treas. Reg. § 1.263(a)-3(e)(6).
- Examiners who focus on pipeline improvements and repairs should review the statements regarding unit of property for “Network Assets” found in Treas. Reg. § 1.263(a)-3(e)(3)(iii). Agents are encouraged to contact the Deductible and Capital Expenditures Practice Network (DCE Practice Network) for the latest developments in this technical area.

- (5) **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. The following are capitalization issues under IRC § 263A and the regulations thereunder that are common to oil and gas:

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

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, generally, and 1.263A-13, particularly for oil and gas activities.

Interest expense is also capitalized during the production of personal property that has MACRS class life of 20 years or more, an 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. Treas. Reg. § 1.263A-8(a)(1) and (b)(1)(ii).

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). See Rev. Proc. 87-56 for a full discussion on asset classes. Whether interest must be capitalized will depend on the production period or 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 Audit Technique Guide.

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.

Oil and gas companies in the upstream sector also produce offshore platforms. CCA 201211011 addressed whether a “jacket type” platform is an “inherently permanent structure” and should be considered real property for purposes of IRC § 263A(f). While a floating deep-water 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.

The total costs that have capitalized under IRC § 263A for property that was placed in service during the tax year should be reported on Line 23 of Depreciation and Amortization, Form 4562 (Form 4562). If the amount seems negligible a review of the taxpayer’s methodology in arriving at the figure may be warranted.

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.

Companies in the natural gas marketing and transportation sectors may acquire gas for resale. Treas. Reg. § 1.263A-1(b)(8) 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. Treas. Reg. § 1.263A-1(b)(8)(i). 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. Treas. Reg. § 1.263A-1(b)(8)(ii). Other gas in the storage facility that is available to meet customer demand (often called “working gas”) is subject to IRC § 263A.

C.5. Geological and Geophysical Expenditures

- (1) In general, geological and geophysical (“G&G”) expenditures are costs incurred by a taxpayer to obtain, accumulate, and evaluate data that will serve as the basis for the acquisition or retention of mineral properties by taxpayers exploring for minerals. G&G expenditures are usually associated with a survey, such as a seismic, magnetic, or gravity survey conducted by a specialized service company. Seismic G&G “data” refer to the raw acoustic data generated by the surveys as well as the usable visual geologic information (including maps) that results from processing the raw acoustic data. G&G 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 regarding 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 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 expenditure may be both direct and indirect costs. 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 include the salaries of employees who provide technical services to evaluate the survey, as well as the salaries, overhead, and computer processing costs of the department which performs the computer processing of the survey. On occasion, the evaluation and processing are done by vendors or consultants. Examiners should be aware that for financial accounting purposes salaries, computer costs, and overhead costs of employees or contractors who process and evaluate G&G data are routinely charged to expense, but for tax purposes, these costs are capital expenditures that are subject to amortization under IRC § 167(h).
- (4) In 2005, the tax treatment of domestic G&G expenditures was simplified with the enactment of IRC § 167(h), which provides that “any geological and geophysical expenses paid or incurred in connection with the exploration for, or development of, oil or gas within the United States (as defined in IRC § 638) shall be allowed as a deduction ratably over the 24-month period beginning on the date that such expense was paid or incurred.” The half-year convention specified in IRC § 167(h)(2) results in the amortization deduction being spread over three tax years. A G&G expenditure is a capital expenditure and amounts charged to current expense should be closely examined. G&G expenditures may be found to have been deducted as ordinary business expenses under IRC § 162, “Other Professional Expenses” on Line 26 of Form 1120, or IDC. Such accounts should be analyzed for G&G expenditures that are properly subject to amortization under IRC § 167(h).
- (5) For “major integrated oil companies” amounts paid or incurred for G&G expenditures are amortizable over 7 years. See IRC § 167(h)(5)(A). Examiners should note that the definition of “major integrated oil company” could encompass the foreign refining operations of related entities. See IRC § 167(h)(5)(B). 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 subsidiary doesn’t meet the definition based on its own 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 Counsel.
- (6) In *CGG Americas, Inc. v. Commissioner of Internal Revenue*, a corporation incurred expenses for geophysical surveys then licensed the data from the surveys to its customers. Even though the taxpayer was not an oil and gas operator, the Tax Court concluded that the taxpayer had incurred G&G expenditures in connection with oil and gas exploration because its activities were integral to its clients finding oil and gas deposits and IRC § 167(h) is not limited to owners of mineral interests. 147 T.C. 78 (2016).
- (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. See *also* FAA 20163501F (May 2, 2016) (advising that the taxpayer could not immediately deduct the remaining amortizable G&G expenses that it paid or incurred in connection with the exploration and development of the disposed properties nor could the taxpayer include the remaining amortizable G&G expenses in the basis for purposes of computing gain or loss on the sale of the disposed properties. Instead, the taxpayer was required to deduct the remaining G&G in accordance with the original IRC § 167(h) amortization schedule.)

- (8) G&G expenditures incurred with respect to foreign properties are not encompassed in the amortization rules under IRC § 167(h) because IRC § 167(h) is limited to G&G expenses paid or incurred in connection with the exploration for, or development of, oil or gas *within the United States*; such costs are subject to capitalization. See *also* IRC § 617(h). The tax treatment of foreign G&G expenditures is governed by other sections of the Code. Rev. Rul. 77-188, 1977-1 C.B. 76 as amplified by Rev. Rul. 83-105, 1983-2 C.B. 51 may also be instructive. The assistance of an engineer will generally be needed in the examination of these expenditures. See Exhibit 6: Rules Regarding Foreign Geological and Geophysical Expenditures 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 IDC, however, IRC § 167(h) provides the exclusive method of cost recovery for G&G expenditures. CCA 201835004 advised that the cost of seismic surveys used to optimize the placement of offshore oil and gas development wells should be treated as G&G expenditures under IRC § 167(h). The taxpayer did not use data to prepare for or to site specific wells but to determine generally where to drill within two project areas. The treatment of G&G expenditures as IDC is inconsistent with the stated intent of IRC § 167(h), which was to simplify the tax treatment of G&G expenditures and eliminate disputes between the IRS and taxpayers. Furthermore, IRC § 167(h) includes expenses incurred in connection with “the exploration for, *or development of*, oil or gas” meaning that activities that generate IDC deductions may also be G&G expenditures and subject to IRC § 167(h). An examiner that finds that G&G expenditures have been expensed as IDC should develop the facts and contact Local Counsel.

C.6. 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. See Treas. Reg. § 1.263(a)-(2)(f). 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.

C.7. 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 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 was 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 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 held that percentage depletion is allowable on oil and gas lease bonuses and advance royalty income prior to production so long as the income can be attributed to the productive life of the lease. *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 includible in gross income. See Announcement 84-59, 1984-23 IRB 58. Refer to Section VII.D, Percentage Depletion, for additional discussion of percentage depletion.
 - After August 16, 1986, payments in absence of production are not subject to percentage depletion. IRC § 613A(d)(5). See Section II.B.2., Landowner and Fee Royalty Owner.

- (6) Examination of the lease record (which includes the royalty agreement), the journal entries recording minimum royalty transactions, and the related ledger accounts are proper steps to verify these transactions.

C.8. Top Leasing

- (1) If a lease expires, any capitalized cost of the lease may be recovered as 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 of review 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.

C.9. 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 relating to 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.

C.10. Allocation of Geological and Geophysical Expenditures

- (1) The G&G expenditures incurred in an area must be allocated to the leases acquired and retained therein. This can best be illustrated by the following example:
 - Oil Company A, 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 per acre must

be paid on the selected acreage, and a delay rental of \$2 per acre per annum be paid on the selected acreage. The preliminary survey, core drilling, and other G&G costs amounted to \$24,000. Prior to the expiration of the first 6-month period, Oil Company A selected 2,500 acres under the lease for which they paid \$25,000 bonus.

- The \$40,000 option cost, the \$24,000 geological and geophysical expenditures, if paid or incurred prior to the enactment of the Energy Policy Act of 2005, and the \$25,000 bonus should be capitalized as leasehold costs of the 2,500 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 geo-physical 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.
- (2) For G&G incurred prior to the enactment of the Energy Tax Incentives Policy Act of 2005, remember that all the 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 whether an option was obtained as a protective measure during the study. See Rev. Rul. 77-188, 1977-1 CB 76.

C.11. 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 (*i.e.*, the 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. Treas. Reg. § 1.611-1(d)(4). The cost basis is allocated between leasehold and equipment in proportion to their fair market value (FMV). Treas. Reg. § 1.611-2(d). See *also* 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:

The allocation schedule and method.

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 of 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. Treas. Reg. § 1.611-2(d). 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 look 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 (a/k/a Correlative Adjustments) issue because the seller and buyer might allocate the total price in a unique manner that benefits them from an income tax standpoint. For example, the buyer might skew a higher percentage of the purchase to depreciable assets, which may be recovered relatively quickly via MACRS depreciation, and a lesser percentage to depletable basis, which is recovered via depletion over the producing life of the properties. Conversely, the seller might skew the allocation of the total sales price in a different manner to achieve the optimum amounts of capital gain and ordinary income. Such disparate treatment is aided by the subjective nature of determining the fair market value of oil and gas equipment and leases in various states of development. The buyer and seller seldom value the property in a like manner. 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. See IRM 4.10.13.5 Adjustments Between Correlative U.S. Taxpayers to Achieve Consistent Tax Treatment (a/k/a Whipsaw Issues).
- (10) On the sale of IRC § 1245 property and non-IRC § 1245 property, if buyer and seller have adverse interests as to the allocation of the amount realized between IRC § 1245 property and non-IRC § 1245 property, any arm's-length agreement between buyer and seller will establish the allocation. Treas. Reg. § 1.1245-1(a)(5).
- (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.

D. 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 Audit Technique Guide, 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.

D.1. 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 common practice for the promoter or sponsor of a drilling package to acquire part or all the interest in the drilling venture in return for services. The receipt of an interest in a drilling venture in return for capital and services furnished by a driller and equipment supplier for use in development of the lease property is not taxable on receipt. See GCM 22730 (January 1, 1941), 1941-1 CB 214 (relying on *Palmer vs. Bender*, 287 U.S. 551 (1933)). GCM 22730 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.
- (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, but subsequent changes in tax laws and subsequent court cases have significantly limited the use of GCM 22730. The following are examples of limitations to GCM 22730:

IRC § 61 stating gross income means all income from whatever source derived including services.

IRC § 83 stating if property is received in exchange for services, then the FMV of the property received in excess of the amount paid for the property shall be included in gross income of the person who performed the services.

1.721-1(b) stating the receipt of property as payment for services rendered is taxable income to the extent of the fair market value of property received.

James A. Lewis Engineering Inc. v. Commissioner, 339 F.2d 706 (5th Cir. 1964) (rejecting the application of GCM 22730 because the interest received in exchange for services was related to production activity and not development activity); 15 AFTR 2d 9; 65-1 USTC 9122;

Diamond v. Commissioner, 56 T.C. 530 (1971) (finding the readily ascertainable FMV of taxpayer’s interest in a partnership received in exchange for services in obtaining a mortgage loan was ordinary income to him under IRC § 61(a)(1)); 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) (remanding for a determination of whether the FMV of stock received in exchange for services was taxable as ordinary income, except the part that was attributable to a contribution of maps to venture, where geologist contributed his maps and services to locate oil deposits and acquire properties in name of partnership for monthly salary and expenses without any ownership in properties until the partnership had

recovered costs, and contract was terminated and acquired properties transferred to corporation).

- (4) Treas. Regs. §§ 1.83-1(a), 1.83-2(a), and 1.83-3(a) provide rules for the taxation of property transferred to an employee or independent contractor (or beneficiary thereof) in connection with the performance of services by such employee or independent contractor. In general, such property is not taxable under IRC § 83(a) until it has been transferred (as defined in Treas. Reg. § 1.83-3(a)) to such person and become substantially vested (as defined in Treas. Reg. § 1.83-3(b)) in such person. Treas. Regs. § 1.83-1(a). The person performing such services may elect to include in gross income the excess (if any) of the fair market value of the property at the time of transfer (determined without regard to any lapse restriction, as defined in Treas. Reg. § 1.83-3(i)) over the amount (if any) paid for such property, as compensation for services. IRC § 83(b); Treas. Regs. § 1.83-2(a). Treasury issued final regulations in 2016 that removed the second sentence in Treas. Reg. § 1.83-2(c) of the existing regulations, which required that a taxpayer submit a copy of an IRC § 83(b) election with the taxpayer's tax return for the year in which the property subject to the election was transferred. T.D. 9779. Accordingly, for property transferred after January 1, 2016, a taxpayer is no longer required to file a copy of an IRC § 83(b) election with the taxpayer's income tax return. Treas. Regs. § 1.83-2(c) and (g). Finally, for purposes of an IRC § 83 and the regulations thereunder, a transfer of property occurs when a person acquires a beneficial ownership interest in such property (disregarding any lapse restriction, as defined in Treas. Reg. § 1.83-3(i)). Treas. Regs. § 1.83-3(a). Treasury issued final regulations in 2014 that provide several clarifications regarding whether a substantial risk of forfeiture exists in connection with property subject to IRC § 83. T.D. 9659. Specifically, T.D. 9659 clarify that:

Except as specifically provided in IRC § 83(c)(3) and Treas. Regs. §§ 1.83-3(j) and (k), a substantial risk of forfeiture may be established *only if* rights to the property transferred are conditioned through a service condition or a condition related to the purpose of the transfer. Treas. Regs. § 1.83-3(c).

In determining whether a substantial risk of forfeiture exists based on a condition related to the purpose of the transfer, both the likelihood that the forfeiture event will occur and the likelihood that the forfeiture will be enforced must be considered. Treas. Regs. § 1.83-3(c).

Except as specifically provided in IRC § 83(c)(3) and Treas. Regs. §§ 1.83-3(j) and (k), transfer restrictions do not create a substantial risk of forfeiture, including transfer restrictions that carry the potential for forfeiture or disgorgement of some or all of the property, or other penalties, if the restriction is violated. Treas. Regs. § 1.83-3(c).

- (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 may 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, as clarified by Rev. Proc. 2001-43, 2001-2 CB 191 provides guidance on the treatment of 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. Generally, the Service will not treat the receipt of such an interest as a taxable event for the partner or partnership subject to three exceptions. *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:

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.

The services contributed may not in effect be a substitution of capital.

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.

The contribution must be specific to the property in which the economic interest is earned.

The contribution must be definite and determinable.

The contributor must look only to the economic interest for the possibility of profit.

D.2. 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.

D.3. 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 Section II.D.8, Farm-in and Farm-out, and Rev. Rul. 77-176, 1977-1 CB 77.
- (2) Rev. Rul. 77-176, provides examples of the tax treatment to be afforded to the carrying party (operator) and the carried party (lease owner) when an operating interest in an oil and gas property is received in exchange for drilling a well. Generally, the driller will be entitled to deduct 100 percent of the IDC incurred in drilling the well, if the arrangement is a true carried interest. See *also* Section IV.I.4, Carried Interest. 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 the 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. Rev. Rul. 77-176

D.4. 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 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 recapture, regarding

investment tax credits and depreciation, if a gain results. See IRC § 50 and IRC § 1245.

D.5. 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, among other things, 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. See Treas. Reg. § 1.636-3(a)(1) and (2) and Section VI.B.4, Assignment of Income, for further definition.
- (2) Prior to the Tax Reform Act of 1969 and the enactment of IRC § 636, 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, 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 enactment of the 1969 Tax Reform Act, IRC § 636 specifically excludes production payments from the definition of economic interest and treats mineral production payments as loans. But, production payments carved out for exploration or development are generally excepted from treatment as loans under IRC § 636. See *also* Treas. Reg. § 1.611-1(b). Therefore, the acquisition of a property burdened by a production payment is usually similar to the purchase of a property encumbered by a mortgage.

D.6. 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. Treas. Reg. § 1.614-1(a)(3). However, government leases are an exception to the rule above. 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. See Rev. Rul. 68-566, 1968-2, CB 281.
- (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) 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, paying the filing fees and paying the 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 have 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.

The BLM announces the tracts by size, legal description, and date they are to be available for leasing.

Interested persons may file an application to lease any or all tracts but each separately described lease requires a separately filed lease application.

A nominal nonrefundable filing fee of \$10 is required for each filing application.

A person may file only one application for any one tract.

On the prescribed date, a lottery-type drawing is held by the BLM.

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 fee is charged for entry in the "drawing."

The winner is awarded a property far in excess of the entry fee plus delay rentals.

The fee is nonrefundable.

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, under the following facts, that first-year rentals paid for a Government lease were a capital investment in an overriding royalty where:

The taxpayer filed an application for a Government lease and paid the first-year rental.

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 Rev. Rul. 67-141, 1967-1 CB 153.

D.7. 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 Section VI.C.2, Operating Expense vs. Intangible Drilling Costs (IDC) vs. Capital.

D.8. 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. See Section II.D.3, Drilling as Consideration for Property Outside of the Drill Site, 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.

III. Types of Organizations

A. Introduction

- (1) This section discusses the many types of organizations in the oil and gas industry.
- (2) Many forms of organizational structures can be found in the oil and gas business. An individual may act alone but will normally conduct business as a co-owner with others in a joint venture during the drilling, development, and operation of the oil and gas business. While some taxpayers choose to form a partnership or other passthrough entity, the tax aspects of which are governed by Subchapter K of the Code, it is very common for them to form joint ventures and elect out of the application of Subchapter K. See IRC 761; Treas. Reg. § 1.761-2.
- (3) These joint ventures can give rise to certain tax advantages that cannot be achieved in other ownership forms of doing business. This is especially true during the development period of the oil and gas business.
- (4) The corporate form of organization is also used to conduct the operations of the oil and gas business. Even though the corporate form of doing business has certain business advantages, there are significant tax disadvantages of using this form to conduct oil and gas operations. The use of the “Subchapter S” corporate form is sometimes used in oil operations but is not as common because the qualifications for its use are restrictive. It also has some of the tax disadvantages of the regular C corporate form of business.

B. Individuals

- (1) The tax consequence regarding the cost of drilling and operating oil and gas properties is a very important item an individual takes into consideration before the decision is made to explore and operate oil and gas leases. There are special provisions of the law that recognize these business decisions and give the individuals, co-owners, partnerships, corporations, and other forms of business the elections to currently deduct the cost of what would otherwise be a capital expense. There are other elections the taxpayers can make in order to receive the maximum tax benefits available to oil operators.

B.1. Elections

- (1) **Intangibles and Delay Rentals.** The election to expense intangible drilling and development costs must be made by a taxpayer in the return for the first year in which such costs are first paid or incurred. See IRC § 263(c) and Treas. Reg. §

1.612-4(d). The election is made by claiming the intangible drilling and development costs as a deduction on the return and, when made, is binding for all future years. Treas. Reg. § 1.612-4(e) This election includes the right to deduct intangible drilling and development costs on productive and nonproductive wells. The failure by the taxpayer to deduct such expenses is deemed to be an election by the taxpayer to capitalize such costs. Such capitalized costs are thereafter recovered through the deductions of depletion. However, for treatment of IDC paid or incurred after 1982, IRC § 59(e) and IRC § 291(b) apply. See Section IV.D, Election Regarding Intangible Drilling and Development Costs. Delay rentals are required to be capitalized under IRC § 263A.

B.2. Co-Owners

- (1) Taxpayers who are co-owners of oil and gas properties and have not elected to be excluded from the provisions of Subchapter K of the Code must make a partnership level election to expense intangible drilling and development costs. If the partnership elects to capitalize such costs, the individual partners are bound by that election and may not deduct those costs on their individual returns.

B.3. Mineral Properties

- (1) For the purpose of computing allowable depletion and any gain or loss on the disposition of oil and gas minerals, the term “property” is important. “Property” means each separate interest owned by the taxpayer in each mineral deposit in each separate tract or parcel of land. IRC § 614(a). The Code provides that all of the taxpayer’s operating mineral interests in a separate tract or parcel of land are to be treated as one property unless taxpayer elects to treat such interests as separate properties. IRC § 614(b)(2). The election to treat each property as a separate property must be made in the first year the taxpayer makes any expenditure for development or operation of the property interest. IRC § 614(b)(4). The election must be made by attaching to the return a specific statement describing the tract and all the operating interest owned in the tract and must indicate which operating interests are being combined and which are being kept separate. Treas. Reg. § 1.614-2(d)(2). Once the election is made, it is binding for all subsequent years. IRC § 614(b)(4).
- (2) The agent should make sure that the taxpayer is combining all income and expenses from the properties on tracts that are producing from different zones unless the proper election has been made to treat them separately.

B.4. Reporting on Tax Return

- (1) The income from different types of oil and gas activities is reported by individuals on different schedules on their *U.S. Individual Income Tax Return*, Form 1040 (Form 1040). Royalty income is reportable by an individual on Form 1040, *Supplemental Income and Loss*, Schedule E (Schedule E), unless the royalty income is an integral part of a trade or business. Incomes received from

lease bonuses and delay rentals are also reported on Schedule E. Royalty income reported on Schedule E, generally, is not subject to self-employment taxes. Royalty owners do not pay production expenses other than taxes.

- (2) An individual who owns a working interest reports production income from oil and gas on Form 1040, *Profit or Loss from Business*, Schedule C (Schedule C). Royalty income which is an integral part of a trade or business is also included in Schedule C. Working interest and royalty income reported on Schedule C are considered trade or business income and are subject to self-employment taxes.
- (3) For tax years beginning on or after January 1, 2013, IRC § 1411 establishes a 3.8% surtax on certain individuals, estates and trusts with net investment income and modified adjusted gross income above statutory threshold amounts. In general, net investment income includes, but is not limited to, interest, dividends, capital gains, rental and royalty income, and non-qualified annuities income from businesses involved in trading of financial instruments or commodities and businesses that are passive activities to the taxpayer (within the meaning of IRC § 469). In calculating net investment income, gross investment income is reduced by certain expenses properly allocable to such income.

Income from oil and gas properties may be subject to the IRC § 1411 surtax, depending on the payment involved. A typical oil and gas development operation involves (i) the mineral interest owner (the royalty owner), (ii) the operator (the working interest owner), and (iii) investors who provide funding and receive an interest in the activity in exchange for their capital investment. A partnership is usually created to report the income and expenses associated with the development of oil and gas properties. Because the funding partners are merely investors in the activity, their deduction of reportable losses may be limited under the passive loss rules of IRC § 469. Similarly, the receipt of investment-related oil and gas income such as bonus payments, royalties, and delay rentals would also be subject to the 3.8% surtax. In contrast, a working interest owner is treated as being engaged in a non-passive activity, regardless of his or her participation, and the oil & gas income received is subject to self-employment tax. Temp. Treas. Reg. § 1.469-1T(e)(4)(i). *See also Methvin v. Comm’r*, T.C. Memo 2015-81, *aff’d.*, 653 *Fed. Appx.* 616 (10th Cir. 2016) (holding that investors with income from working interests in which they were not materially participating were subject to self-employment tax on properties owned by entities regardless of electing out of the application of Subchapter K).

The IRS has posted Questions and Answers on the [Net Investment Income Tax on IRS.gov](#).

B.5. Loss Limitations

- (1) The losses realized from certain “activities” are limited to the amounts a taxpayer has “at-risk” with regard to those activities at the end of the tax year. See IRC § 465. The otherwise deductible loss from the “activity” of exploring or exploiting oil and gas reserves could be limited by the at-risk rules of IRC § 465.

Each separate oil and gas property constitutes a separate activity. IRC § 465(c)(2). Any losses which are limited by IRC 465 will be allowed as a deduction in the next succeeding tax year, provided there is additional at-risk basis of property at the end of that year. IRC § 465(a)(2) and (b)(5). The amounts a taxpayer has at-risk with respect to an activity are as follows:

Cash;

Adjusted basis of property contributed to the activity;

Personal liability for indebtedness; and,

Fair market value of assets outside the activity securing nonrecourse liabilities within the activities.

Note: In addition to the loss limitation provision, the law also provides for a recapture of previously allowed losses when the taxpayer's at-risk amount is reduced below zero. See IRC § 465(e).

- (2) Examining agents need to keep in mind, to be able to deduct losses from oil and gas activities, individuals must have a sufficient amount at-risk within the meaning of IRC § 465. This can be thought of and is sometimes referred to as "at-risk basis". For example, if the taxpayer is engaged in a drilling program that is financed with borrowed funds and the leases are operating at losses, the examination should be extended to verify that the at-risk provisions of the law are being met. If the at-risk limitations are found to apply to a given oil and gas property, the transfer of lease equipment from that property to another property may trigger a realization of ordinary income under IRC § 465(e) because the assets at risk with respect to that particular activity have been decreased. Disposition of a property is not necessary for ordinary income to be realized; reduction of at-risk basis below zero can create income realization.

C. Partnerships

- (1) For many years, the partnership has been a favorite vehicle for conducting oil and gas drilling ventures. The popularity of the partnership form in oil and gas ventures is largely due to the flexibility allowed by Subchapter K. The special allocations of income, gain, loss, deductions, or credits (or item thereof) allowed by IRC § 704(b) fit the need to share the risk and the financing of oil and gas ventures. Your study of Subchapter K in school will not be repeated here; however, certain features of partnership law that are of importance in oil and gas partnerships will be discussed.
- (2) Examiners should always determine whether the partnership is subject to the Tax Equity and Fiscal Responsibility Act (TEFRA) audit rules or the Bipartisan Budget Act of 2015 (BBA) centralized audit regime, which will require an examination at the partnership level in order to make adjustments to partnership items. For example, depletion and IDC have both partnership-level and partner-level components that should be distinguished.

- (3) The partnership form of doing business assists oil companies in obtaining financing for oil and gas drilling ventures by permitting unrelated investors to join as partners. Thus, a company is able to finance the drilling costs as well as share the risk in drilling for oil and gas.
- (4) The sponsor of an oil and gas drilling partnership may draft a partnership agreement so that most of the IDC of drilling an oil or gas well may be specially allocated to certain investors, as long as these allocations have substantial economic effect under IRC § 704(b). The current tax deduction allowed for IDC, by IRC § 263(c), is an incentive to the investors for risking capital in a drilling venture.
- (5) Prior to the Tax Reform Act of 1976, promoters of oil and gas drilling ventures often utilized nonrecourse loans to provide deductions for limited partners in excess of their economic investment. This practice was questionable at best and generally lacked economic substance. IRC § 465(b)(6) provides that the deduction for losses incurred in oil and gas ventures (among other activities) cannot exceed the amount “at-risk”. Therefore, normally, a limited partner’s loss deduction cannot exceed the money invested. Agents should closely scrutinize promoter financing for these ventures. Usually, the loans in most contemporary drilling ventures will be guaranteed by the partners and backed up with solid collateral. If this is the case, the loan is recourse and will increase the outside basis of the party who provides the collateral and guarantee. See IRC § 752. If a limited partner does not guarantee the loan, he will not be considered at risk because he is protected from recourse on the loan due to his status as a limited partner, and his deductions would be limited accordingly. Note that the at-risk rules are generally applicable to individuals and only in very limited circumstances to closely held corporations.
- (6) Nonrecourse financing is sometimes used to increase the amount of deduction for IDC. However, nonrecourse financing generally does not give rise to at-risk basis unless it is secured by the taxpayer’s own property. Accordingly, IRC § 465 has generally eliminated the use of nonrecourse financing for individuals after January 1, 1976. See Section III.C.8, Deduction for Partnership Losses, for further information. See IRC § 465(b)(6) for the treatment of qualified nonrecourse financing.

C.1. Exclusion from Subchapter K

- (1) The typical oil and gas joint venture between working interest owners is technically a partnership for federal tax purposes. See IRC § 761 for definition of “partnerships”.
- (2) IRC § 761(a) and Treas. Reg. § 1.761-2(a)(3) and (b) permit participants in the joint production, extraction, or use of property to be excluded from the in the application of Subchapter K, if all other requirements are met. This election is made by attaching a statement to a partnership return. Treas. Reg. § 1.761-2(b)(2). The election can be made in any year in the life of a partnership, including the first year. However, until the election is made a partnership return

must be filed, and the joint venture will be subject to the partnership provisions in the Code. Once the election is filed, the joint venture ceases to file a partnership return and the joint interest owners or working interest owners may not consider themselves to be partners.

- (3) If the partnership elects to be excluded from the provisions of Subchapter K, each partner will make the election to capitalize or deduct IDC. If the partners have made a previous election, they will be required to follow it.
- (4) If a partnership does not elect to be excluded from Subchapter K, the partnership itself must make all elections affecting taxable income of the partnership, except for any election under:
 - IRC § 108 (regarding income from discharge of indebtedness);
 - IRC § 617 (regarding deduction and recapture of certain mining expenses); and
 - IRC § 901 (regarding taxes of foreign countries and U.S. possessions).
- (5) IRC § 703 and Treas. Reg. § 1.703-1(b) provide for elections that are made by the partnership instead of by individual partners. The most important election made by an oil and gas partnership is the election to capitalize or deduct IDC. The election to deduct currently or capitalize must be indicated on the first partnership return claiming such expenses. Failure to elect to deduct IDC on a partnership return will sometimes preclude the passthrough of IDC to the individual partners. Frequently, taxpayers fail to realize that a partnership return must be filed, and they fail to elect to be excluded from the provision of Subchapter K. When this happens, the election to deduct IDC currently cannot be made by the partnership; therefore, IDC may be capitalized at the partnership level. Moreover, in cases where a partnership does elect to expense IDC and passes through the IDC deduction to its partners, the partners may elect to capitalize and amortize IDC as provided in IRC § 59(e) for alternative minimum tax purposes.
- (6) Certain elections are important and should be made at the partnership level, including the following expenditures:
 - Intangible drilling and development costs - to deduct or capitalize. See IRC § 263(c).
 - Property unit - to treat as one property or separate properties. See IRC § 614.
 - Subchapter K - election to not be treated as a partnership. See Treas. Reg. § 1.761-2.
- (7) Partners are subject to self-employment taxes on their share of working interest income of a partnership that elects out of the application of Subchapter K. General partners are also subject to self-employment taxes on their share of partnership working interest income where a partnership has not elected out of the application of Subchapter K. Limited partners are not subject to self-employment taxes on their share of limited partnership income. See IRC § 1402.

C.2. Sharing Income and Deductions

- (1) With partnerships, it is important to remember that a partner's share of income and deductions will be determined by the partnership agreement. See IRC § 704. Enterprising oil and gas promoters use IRC § 704 to allocate current deductions to investors who furnish money for drilling wells.
- (2) Generally, the pure economics of drilling a "wildcat well" do not offer sufficient benefits to entice outside investors to furnish money for drilling. However, if the general partner or promoter can allocate all of the current tax deductions to certain investors, the tax benefits are often sufficient to justify the investment. IRC § 704(b) permits unequal allocations of deductions among partners, which are called special allocations, as long as the allocation has substantial economic effect. See *Orrisch v. Commissioner*, 55 T.C. 395 (1970) for an illustration of the substantial economic effect rules.
- (3) Where an allocation does not affect the partner's capital upon liquidation, it will not usually be considered to have substantial economic effect. In such a situation, if the allocation is determined to lack substantial economic effect, the item will be reallocated in accordance with the partners' interest in the partnership. Generally, this means the item will be shared among the partners on a per capita basis. An easily understood discussion on partnership allocations can be found in Cunningham and Cunningham, *The Logic of Subchapter K, A Conceptual Guide to the Taxation of Partnerships*, 6d (West Group, 2020).

C.3. Allocation of Depletion

- (1) The Tax Reform Act of 1975 added IRC § 703(a)(2)(F) to provide that the deduction for depletion under IRC § 611 is not allowable as a deduction to a partnership. After January 1, 1975, the depletion deduction must be deducted on a partner's return, not the partnership return. IRC § 613A(c)(7)(D). Due to IRC § 613A, each partner must now compute the limitations for their depletion deduction on their own return. Each partner treats an allocable portion of the partnership's basis in the property as its basis for cost depletion computation purposes. Treas. Reg. § 1.613A-3(l) provides that the partnership is responsible for providing each partner with the information necessary to compute depletion deductions.

C.4. Partnership Formation Costs

- (1) All partnerships incur certain formation costs such as legal fees, officers' salaries, administrative expenses, and broker's fees for selling partnership units or shares. Sometimes these expenses are paid by the general partner, promoter, or sponsor and sometimes they are paid by the partnership. After October 22, 2004, the partnership can elect to deduct the lesser of (i) the organizational expenses with respect to the partnership or (ii) \$5,000 reduced (but no below zero) by the amount that organizational expenses exceed

\$50,000. Any remaining organizational expense is deducted pro rata over 180 months. IRC § 709(b)(1).

- (2) On or before October 22, 2004, costs of forming a partnership are capital in nature and are not allowable as a current deduction. See IRC § 709(a) (prior to Pub. L. 108-357). IRC § 709(b) (prior to Pub. L. 108-357) does, however, permit amortization of organization fees over a 60-month period.
- (3) Formation costs may not be evident in the partnership return or in the books and records of the partnerships. When this is the case, such costs may be found on the return of the partnership sponsor or promoter. Therefore, the agent should review and, if necessary, examine the sponsor, promoter, or general partner concurrently with the examination of the partnership so that the proper treatment of these costs can be ascertained.
- (4) In large, limited partnerships, it is a usual practice to sell partnership units through a stock brokerage firm. These firms usually charge a commission ranging from 5 percent to 10 percent of the entire partnership capital. These costs are syndication costs (rather than organization costs) which cannot be deducted or amortized. Treas. Reg. § 1.709-2(b). This can be a rather sizeable adjustment and can usually be found by a careful reading of the partnership prospectus.
- (5) Large management fees paid in the first year of the partnership can be an indication that the partnership is reimbursing the sponsor for formation costs. A careful reading of the prospectus and inquiries to the managing partner can uncover this issue. However, in some cases, an examination of the sponsor's books and records is the only way to accurately determine the actual amount and nature of the formation costs.
- (6) While the agent can usually speculate that a certain percentage of the first-year management fee is for formation costs, this determination may not be sustained if a taxpayer later purports to show the actual formation costs to an appeals officer or to the court. Therefore, it is advisable to determine the actual amount and nature of the organization costs instead of relying upon an arbitrary percentage adjustment. See IRC § 709.

C.5. Special Item Allocations

- (1) Special partnership allocations such as losses and depreciation are equally valid in oil and gas partnerships.
- (2) Common practice in oil and gas partnerships is for currently deductible costs to be allocated to certain partners. For instance, intangible drilling costs, well completion costs, and operating costs may be allocated entirely to limited partners. Special allocations are permitted under IRC § 704, but they must have substantial economic effect. A review of IRC § 704(b) and Treas. Reg. § 1.704-1(b) will provide guidance in this area.

C.6. Reasonableness of Intangible Development Costs in a Partnership

- (1) Examiners should not accept a canceled check as proof of the amount of the deduction for intangible drilling and development costs without additional supporting documents. Frequently, promoters and sponsors of oil and gas ventures inflate the actual drilling costs to include an excessive profit for themselves. In some cases, examiners have found that the IDC are inflated several times over the actual costs. The amount in excess of the actual cost plus a reasonable profit should be considered to be paid for leasehold cost and capitalized by the partnership. See Rev. Rul. 73-211, 1973-1 CB 303. When the reasonableness of drilling costs is in question, the examiner should consult a petroleum engineer.
- (2) Oil and gas wells vary in depth according to the area, drill site location, and formation to be tested. It is much more expensive to drill a deep well than a shallow well. The drilling cost per foot of hole is much greater for a well drilled to a depth of 15,000 ft. than for a well drilled to 1,000 ft. There are several reasons why the drilling costs per foot are not constant. The area of country, environment, rock formations, and other factors contribute to the ease or difficulty of drilling a hole. Other factors are the size and quality of the equipment. At deep depths, greater pressure and drill stem weight require larger drilling rigs, pumps, drill stem, surface casing, mud, etc.

Example: a well drilled to a depth of 5,000 ft. in West Central Texas will differ substantially from the cost of a well of the same depth in southern onshore Louisiana. The cost per foot of well drilled in deep water (*i.e.*, 1000 feet or more) and many miles from the coast of Louisiana might be five times greater compared a well drilled to onshore Louisiana. In 1999, the average cost in the U.S. was \$139 per foot for onshore wells and \$514 per foot for offshore wells. As stated above, the cost of a well will vary according to area, depth, location, and other factors. Therefore, the costs above represent estimates only and should not be relied upon as more than that. An agent should consult an IRS petroleum engineer if there is doubt over the validity of actual drilling costs.

C.7. Leasehold Costs

- (1) Frequently, a general partner or sponsor of a partnership will acquire an oil and gas lease from a landowner or by taking a “farm-in” and transfer the lease to a partnership as a capital contribution.
- (2) Usually the lease cost is nominal, and the limited partners never pay for any lease cost. The limited partners do actually pay for the leasehold interest indirectly by paying more than their share of the IDC. However, this is permitted under present law if the special allocation has substantial economic effect. See IRC 704(b) and the regulations thereunder. On the other hand, if the leasehold cost is substantial and the amount paid by the limited partners for IDC appears to be excessive, the agent should determine if the general partner has made an

excessive profit on IDC from the drilling contract. If this is the case, the excessive amount of IDC should be considered to have been paid for the leasehold interest and capitalized accordingly. See Rev. Rul. 73-211.

C.8. Deduction for Partnership Losses

- (1) A partner's share of losses incurred by a partnership in a trade or business should be deducted on Form 1040, Schedule E as an ordinary loss. However, IRC § 704(d) limits the loss deduction to the partner's basis in his partnership interest, computed at the close of the year. The loss disallowed is suspended and can be deducted in later years if the partner's basis in the partnership interest increases above zero. See *also* IRC §§ 465 and 469 for additional loss limitations.
- (2) Losses from the sale of capital assets retain their character and pass through separately to the partners. IRC § 702(b). Normally, the sale of oil and gas leases and of equipment on oil and gas leases are considered to be sales of assets used in a trade or business and, thus, are treated as IRC § 1231 property.
- (3) Prior to the Tax Reform Act of 1976, promoters of oil and gas drilling ventures often utilized nonrecourse loans to provide deductions for limited partners in excess of their economic investment. This practice was questionable at best and generally lacked economic substance. IRC § 465(b)(6) provides that the deduction for losses incurred in oil and gas ventures (among other activities) cannot exceed the amount "at-risk". Therefore, normally a limited partner's loss deduction cannot exceed the money invested. Agents should closely scrutinize promoter financing for these ventures. Usually, the loans in most contemporary drilling ventures will be guaranteed by the partners and backed up with solid collateral. If this is the case, the loan is recourse and will increase the outside basis of the party who provides the collateral and guarantee. See IRC § 752. If a limited partner does not guarantee the loan, he will not be considered at risk because he is protected from recourse on the loan due to his status as a limited partner, and his deductions would be limited accordingly. Note that the at-risk rules are generally applicable to individuals and only in very limited circumstances to closely held corporations.
- (4) A productive well has value and will increase the value of all the leased acreage surrounding the drill site. At this stage, a lending institution would likely make a legitimate loan on the property assuming the well is a good one and the partners obtained an appraisal from an independent geologist. In such a situation, the partners' at-risk basis would be increased if the loan were a recourse loan - that is, if the partners were personally liable for repayment of the loan. Where situations of this kind exist, a careful reading of the underlying documents and IRC § 465 is in order. In cases where a partnership loss is involved, loans that increase a partner's basis and amount at risk must be looked at carefully to determine if the loans are legitimate.

C.9. Partnership Capital

- (1) IRC § 721 states that no gain or loss shall be recognized to a partnership or any of its partners when property is contributed to a partnership in return for an interest in the partnership. § 722 provides that the basis of an interest in a partnership acquired by a contribution of property shall be the amount of such money and the adjusted basis of the contributed property other than money. Generally, no recapture of investment credit, or amounts under IRC §§ 1245 (b)(3), 1254 and Treas. Reg. § 1.1254-2(c) will be triggered by a contribution of property by a partner to a partnership.
- (2) However, the nonrecognition provisions of IRC § 721 do not apply to a transfer of property where a party is not acting in the capacity as a partner. See Treas. Reg. § 1.721-1(a). The substance of a partner-partnership transaction should govern instead of the form. If a partner sells property to a partnership for money and notes, in his capacity other than as a partner, the transaction should be treated as a sale in accordance with IRC § 707.
- (3) A frequent occurrence in oil and gas partnerships is for limited partners to supply funds for IDC and receive an interest in the partnership of 50 to 60 percent. The sponsor or general partner will furnish services, a lease, and depreciable equipment, if needed, in return for a 40 to 50 percent interest in the partnership. Treas. Reg. § 1.721-1(b)1 provides that, if one partner gives up the right to be repaid contributions of capital in favor of another partner who renders services, IRC § 721 will not apply. The Regulations further provide that the “value of interest in such capital so transferred to a partner as compensation for services constitutes income to the partner under IRC § 61. The amount of such income is the fair market value of the interest in capital so transferred.” In all cases where a partner receives a transfer of capital from another partner for rendering services, agents should carefully scrutinize the transaction -- examples include if the capital contributed by a partner will not be returned upon liquidation of the partnership or if the partner receives income for providing services. On the other hand, if the partner receives a profits interest rather than a capital interest in the partnership, the receipt of such an interest is not ordinarily a taxable event for either the partner or the partnership unless: (i) the profits interest has a fairly certain income stream; (ii) the interest is in a publicly traded partnership (within the meaning of IRC § 7704(b)); or (iii) the service partner disposes of the interest within two years of receipt. Additional sources of information on this issue were discussed in detail in Section II.D.1, Services Performed for Oil and Gas Property Interests, and include:

IRC § 83.

Treas. Reg. §§ 1.61-1 (a) and 1.721-1(b).

Diamond v. Commissioner, 56 T.C. 530 (1971); aff'd, 492 F.2d 286 (7th Cir. 1974); 33 A.F.T.R. 2d 852; 74-1 USTC 9306

United States v. Frazell , 335 F.2d 487 (5th Cir. 1964); 14 AFTR 2d 5378; 64-2 USTC 9684; cert. denied, 380 U.S. 961 (1965)

Campbell v. Commissioner , TC memo 1990-162 (1990), aff'd in part and rev'd in part, 943 F.2d 815 (8th Cir. 1991)

Rev. Proc. 93-27, 1993-2 CB 343, clarified by Rev. Proc. 2001-43, 2001-2 C.B. 191.

- (4) It is not uncommon for a partner to contribute property to a partnership with a tax basis different from its fair market value. See also IRC §§ 722 and 723. If so, IRC § 704(c) requires that a partnership must use a reasonable method to allocate deductions attributable to the contributed property to the non-contributing partners (to the extent possible) based on its book value. Furthermore, if the contributed property is sold by the partnership, the pre-contribution gain or loss must be allocated to the contributing partner.

C.10. Disguised Sales

- (1) “Disguised Sales” are transactions in which taxpayers may attempt to use partnership structures to avoid sale treatment (*i.e.*, realization of gain) on the exchange or other disposition of their highly appreciated oil and gas properties. These properties typically have high “built-in” gain due to the current deductions of IDC and/or accelerated depreciation of installed equipment. As a result, disguised sale transactions can pose material issues for examination.
- (2) The basic fact pattern and tax treatment of a disguised sale is described as one where a partner directly or indirectly contributes money or other consideration to a partnership and there is a related direct or indirect distribution of money or other consideration by the partnership to the partner (or another partner). The contribution and distribution can occur in any order. Taking into account all the facts and circumstances and viewing the transactions together, if such contribution and distribution are more properly characterized as a sale, then both transactions are treated as a taxable sale. See IRC § 707(a)(2)(B); Treas. Reg. § 1.707-3.
- (3) For more detailed information, refer to Publication 541, Partnerships, and the Partnership Audit Technique Guide.
- (4) Disguised sales pose complex, factually intensive, and time-consuming issue examination. A partnership technical specialist, subject matter expert, and local counsel can help.
- (5) Suggested audit techniques include review of:

U.S. Return of Partnership Income, Form 1065 (Form 1065), *Analysis of Partners' Capital Accounts*, Schedule M-2 (Schedule M-2), for large distributions with corresponding reductions to specific assets on Form 1065, *Balance Sheet for Books*, Schedule L (Schedule L).

Prior, current, and subsequent year Form 1065, *Partner's Share of Income, Deductions, Credits, etc.*, Schedule K-1 (Schedule K-1), searching for large contributions and distributions.

Form 1065, *Net Income (Loss) Reconciliation for Certain Partnerships*, Schedule M-3 (Schedule M-3), for book-to-tax differences for the transaction in question.

SEC filings such as Forms 10-Q, 10-K and 8-K. Company and industry press releases reveal transactions not otherwise disclosed in financial statements. Also, determine how the transaction was treated for both financial and tax purposes.

Structured disguised sale transactions often span multiple tax years. For example, in early years, a taxpayer may reorganize its assets or entities in order to group oil and gas properties that it intends to include in a future transaction. Similarly, a taxpayer could enter into a financial arrangement, such as a production payment or loan, with the other party to the disguised sale several years before the other steps of the transaction occur.

Copies of the contribution agreement, original and amended partnership agreements, any line of credit and/or other loan agreement, any indemnity agreement (or other similar side agreements between partners) as well as a written explanation of the business purpose of these documents. Also, consider requesting any internal financial and tax structuring document and any outside legal or tax advice.

D. Publicly Traded Partnerships

- (1) Publicly traded partnerships (PTP) are fairly common in the oil and gas industry especially for midstream companies. IRC § 7704 allows qualifying publicly traded partnerships to be taxed as a corporation. A partnership whose interests are traded on established securities exchanges or readily tradeable on secondary markets are considered to be publicly traded partnerships.
 - **Exception:** IRC § 7704(c) allows the PTP to maintain its classification as a partnership if 90 percent or more of its gross income is derived from qualifying passive-type income for such taxable year and each preceding taxable year beginning after December 31, 1987, during which the partnership (or its predecessor) was in existence. In general, a taxpayer must continue to meet the gross income requirements on an annual basis to qualify for the exception. Examiners should consider verifying that a taxpayer's income qualifies and that it exceeds 90 percent of gross income.
- (2) IRC § 7704(d) defines "qualifying income" as that term is used in IRC § 7704(c). Qualifying income related to the oil and gas industry includes income and gains derived from the exploration, development, mining or production, processing,

refining, transportation (including pipelines transporting gas, oil, or products thereof), or the marketing of any mineral or natural resource (including fertilizer, geothermal energy, and timber), industrial source carbon dioxide, or the transportation or storage of any fuel described in subsection (b), (c), (d), or (e) of IRC § 6426, or any alcohol fuel defined in IRC § 6426(b)(4)(A) or any biodiesel fuel as defined in IRC § 40A(d)(1). See IRC § 7704(d)(1)(E).

- (3) Treas. Reg. § 1.7704-4, which has an effective date of January 19, 2017, provides that for purposes of IRC § 7704(d)(1)(E), qualifying income is income and gains from qualifying activities with respect to minerals or natural resources as defined in Treas. Reg. § 1.7704-4(b). There are numerous definitions in the regulation and many technical terms. Agents should consider obtaining the services of an IRS engineer.
- (4) Qualifying activities include both IRC § 7704(d)(1)(E) activities (as described in Treas. Reg. § 1.7704-4(c)) and intrinsic activities (as described in Treas. Reg. § 1.7704-4(d)).
 - Treas. Reg. § 1.7704-4(c)(1) provides that IRC § 7704(d)(1)(E) activities include the exploration, development, mining or production, processing, refining, transportation, or marketing of any mineral or natural resource. These terms are defined in Treas. Reg. § 1.7704-4(c)(2)-(8).
 - Treas. Reg. § 1.7704-4(d) provides, in part, that an activity is an intrinsic activity only if the activity is specialized to support an IRC § 7704(d)(1)(E) activity, is essential to the completion of the IRC § 7704(d)(1)(E) activity and requires the provision of significant services to support the IRC § 7704(d)(1)(E) activity. Whether an activity is an intrinsic activity is determined on an activity-by-activity basis.
- (5) Treas. Reg. § 1.7704-4(b)) states that the term mineral or natural resource (including fertilizer, geothermal energy, and timber) means any product of a character with respect to which a deduction for depletion is allowable under IRC § 611, except that such term does not include any product described in IRC §§ 613(b)(7)(A) or (B) (soil, sod, dirt, turf, water, mosses, or minerals from sea water, the air, or other similar inexhaustible sources). For purposes of this section, the term mineral or natural resource does not include industrial source carbon dioxide, fuels described in IRC §§ 6426(b) through (e), any alcohol fuel defined in IRC § 6426(b)(4)(A), or any biodiesel fuel as defined in IRC § 40A(d)(1).
- (6) IRC § 469(k) requires that losses from passive activities of a PTP can only be applied to income or gain from passive activities of the same PTP. Likewise, credits from passive activities of a PTP can only be applied against the tax on the net passive income from the same PTP.

E. Corporations

- (1) The corporate form of organization is often used by investors in oil and gas exploration, particularly if an unusual amount of risk is involved, notwithstanding some unfavorable tax features.
- (2) During the exploration and drilling stage, the adoption of Subchapter S status will enable the stockholders to deduct the losses from operations due to drilling costs being incurred because S corporations are flow-through entities. However, once the properties become profitable, the S corporation shareholder will pay tax on its pro rata share of the corporation's income. In addition, the shareholder of an S corporation having accumulated earnings and profits (generally from a former C-corporation) will pay tax on dividends distributed out of accumulated earnings and profits. See IRC § 1368(c). The percentage depletion deduction does not decrease earnings and profits and has the effect of increasing the taxability of dividends. Treas. Reg. § 1.312-6(c)(1). Earnings and profits are only reduced by cost depletion. Treas. Reg. § 1.316-2(e) provides, in part, "the amount by which a corporation's percentage depletion allowance for any year exceeds depletion sustained on cost or other basis, that is, determined without regard to discovery or percentage depletion allowances for the year of distribution or prior years, constitutes a part of the corporation's earnings and profits accumulated after February 28, 1913, within the meaning of IRC § 316, and, upon distribution to shareholders, is taxable to them as a dividend." This rule is applicable to certain Subchapter S corporations as well as regular corporations. The source of the distribution should be considered for distributions from corporations, including S-corporations, with accumulated earnings and profits, that are considered to be nontaxable. The corporation may be paying a dividend out of a percentage depletion reserve, which will be taxable. See also IRC § 301.

E.1. Alternative Minimum Tax Considerations

- (1) Oil and gas companies often have minimal regular taxable income and therefore the determination of Alternative Minimum Tax (AMT) liability is a very important consideration. The tax preference amount for IDC can significantly affect Alternative Minimum Taxable Income (AMTI). Since other deductions, such as accelerated depreciation, also give rise to a tax preference, examiners should perform a risk analysis prior to proceeding with the examination of any or all tax preference items.
- (2) When the taxpayer is an independent producer (*i.e.*, the taxpayer is not an integrated oil company), examiners should be aware that IRC § 57(a)(2)(E) provides a general exception to the tax preference for IDC. However, that exception is limited and should be reviewed for correctness. See Section III.E.3, Exception for Independent Producers and AMT Limitation.
- (3) For integrated oil companies, another aspect of AMTI to consider is LIFO inventory. See the Audit Technique Guide for Petroleum Refining.

- (4) **Note:** The Tax Cut and Jobs Act of 2017 repealed AMT for corporations. All Code references in Section III.E.1, Alternative Minimum Tax Considerations, Section III.E.2, AMT Computation of IDC Tax Preference Amount, and Section III.E.3, Exception for Independent Producers and AMT Limitation, are to the Code section prior to the enactment of the Tax Cuts and Jobs Act of 2017.

E.2. AMT Computation of IDC Tax Preference Amount

- (1) IRC § 57(a)(2) states that IDC deducted with respect to oil, gas, and geothermal properties is a tax preference to the extent “excess” IDC exceeds 65 percent of the net income from the properties. The preference amount for all geothermal deposits is computed separately from the preference amount for all oil and gas properties that are not geothermal deposits. IRC § 57(a)(2)(D).
- (2) Not all IDC expenditures are taken into account in computing excess IDC. IDC incurred during the year in which the corporation elected to amortize over 60 months pursuant to IRC § 59(e) is not taken into account. See IRC § 263(c). Similarly, IDC incurred with respect to wells drilled outside the U.S. is not taken into account since that IDC must be capitalized. See IRC § 263(i). Lastly, IDC incurred with respect to a nonproductive well (sometimes referred to as a “dry-hole”) is not taken into account. IRC § 57(a)(2)(B)(i). Whether a newly drilled well is nonproductive may be an examination item. Examiners should obtain a list of expenditures for IDC that were classified as nonproductive and then review Section IV.E., Distinction Between IDC and Nonproductive Well Costs.
- (3) Excess IDC is determined annually. The computation steps are as follows:

First, determine how much IDC was paid or incurred during the taxable year in connection with oil, gas, and geothermal wells (other than costs incurred in drilling a nonproductive well) and was deducted under IRC §§ 263(c) or IRC 291(b) for integrated oil companies.

Subtract the amount which would have been allowed as a deduction in the taxable year if such costs had been capitalized and straight-line recovery of intangibles had been used with respect to such costs. See IRC § 57(b).

Under IRC § 57(b), for each well, the taxpayer can compute “straight line recovery” by one of two methods, either straight line amortization over 120 months or by a permitted cost depletion method.

Note: Straight line recovery begins with the month when production from the well commences and is not tied to when IDC was incurred unless the taxpayer elects otherwise. See IRC § 57(b). This could be very significant for high-cost wells that are drilled near the end of the year, especially if the taxpayer made a simplifying assumption that all its IDC was incurred exactly at mid-year and computed six months of amortization.

The following example is based on a Joint Committee on Taxation staff report, General Explanation of the Tax Reform Act of 1986, p. 442.

Example: Assume an integrated oil company incurred \$1,000,000 of IDC in January 2011. It currently deducts 70 percent of that total (\$700,000) under IRC § 263(c). IRC § 291(b) requires that \$300,000 must be amortized over 60 months, yielding a deduction of \$60,000 in 2011. The sum of those two amounts (\$760,000) is compared to how much of the \$1,000,000 IDC would have been allowed in 2011 under straight line recovery. Assume that amount is \$50,000 because production started in July (6 months divided by 120 months and multiplied by \$1,000,000). For 2011 the amount of excess IDC is \$710,000 (\$760,000 minus \$50,000). The remaining IDC to be deducted under 291(b) in subsequent years is disregarded for computing excess IDC in the taxable year. (\$300,000-\$60,000=\$240,000).

- (4) To determine the IDC preference amount, excess IDC must then be compared to 65 percent of “net income from oil, gas, and geothermal properties”. IRC § 57(a)(2)(A). Net income is the gross income the corporation received or accrued from all oil, gas, and geothermal wells minus the deductions allocable to these properties. IRC § 57(a)(2)(C). When calculating net income, only income and deductions allowed for the AMT are considered. The IDC deduction is reduced by the amount of excess IDC. Only deductions incurred with respect to properties that generated gross income during the taxable year are included. IRC § 57(a)(2)(B)(i); see *also* TAM 8002016 (October 5, 1979). However, Rev. Rul. 84-128, 1984-2 CB 15 clarifies that properties which have wells that are capable of production, but which are shut-in, are included in the net income from oil and gas calculation. Presumably the computation is done at the consolidated return level and includes both domestic and foreign properties. However, there is no authority to include activities that occurred within a controlled foreign corporation.
- (5) The following is an extension of the previous example in paragraph (3) of this Section and is intended to show how the tax preference amount is determined:

Example: Assume the facts of the example above. Further assume the company has gross income from oil and gas properties of \$850,000. For simplicity there are no expenses or deductions to consider other than IDC. To determine the AMT net income of the properties, the taxpayer’s regular IDC deduction of \$760,000 must be reduced by the excess IDC of \$710,000, yielding a \$50,000 deduction. Therefore, AMT net income of the properties is \$800,000 (\$850,000 gross income minus \$50,000 AMT expenditures). Sixty-five percent of the AMT net income of the properties is \$520,000 (\$800,000 × 65 percent). Finally, the IDC tax preference amount for the company is \$190,000 (\$710,000 – \$520,000).

- (6) Should taxpayers include the hedging gains and losses in gross income under IRC § 57(a)(2)(C) for the IDC preference for alternative minimum tax?

Taxpayers enter into hedging contracts to manage their exposure to fluctuations in commodity prices for crude oil and natural gas. They will use financial commodity derivative instruments such as price swap, option,

swaption, and collar and basis swap contracts as a means to manage this price risk. They may also use various physical commodity contracts for the sale of hydrocarbons that cover periods of time with varying pricing provisions.

The term “hedge” means a counterbalancing transaction of a futures contract against an actual sale or purchase of a commodity or against a forward sale.

The term “futures contract” means a contract to sell or purchase some fixed amount of the commodity at a future date at a fixed price. The periodic closing of these arrangements results without the extraction and sale of the hedged oil and gas commodity. Future contracts may be closed by (a) purchase of a new contract covering the same amount of the property stipulated without delivery or receipt or (b) by paying or receiving the difference in contract price without delivery or receipt.

The counterparties to the hedging contracts do not purchase oil or gas from taxpayers. The contracts are cash settled, which is typical, for notional principal contracts for oil and gas.

Taxpayers sell their oil and gas production at the wellhead and enter into hedges to try and profit from any favorable price fluctuations between the contract price, as established in the hedging contract, and the market price. In that sense, taxpayers are engaged in a form of price insurance.

IRC § 57(a)(2)(A) states that for AMT, the item of tax preference is with respect to all oil, gas, and geothermal properties, of the taxpayer, the amount (if any) by which the amount of the excess intangible drilling costs arising in any taxable year is greater than 65 percent of the net income from oil, gas, and properties for the taxable year.

IRC § 57(a)(2)(C) states that for purposes of subparagraph (A), the amount of the net income of the taxpayer from oil, gas and geothermal properties for the taxable year is the excess of (i) the aggregate amount of gross income (within the meaning of IRC § 613(a)) from oil, gas, and geothermal properties received or accrued by the taxpayer during the taxable year, over (ii) the amount of any deductions allocable to such properties reduced by the excess described in subparagraph (B) for such taxable year.

IRC § 613(a) states that the allowance for percentage depletion shall be the percentage, specified in subsection (b), of the gross income from the property... Such allowance shall not exceed 50 percent (100 percent in the case of oil and gas properties) of the taxpayer’s taxable income from the property (computed without allowances for depletion and without the deduction under IRC § 199 (or 199A if after the enactment of the Tax Cuts and Jobs Act of 2017)).

Treas. Reg. § 1.613-3 states that in the case of oil and gas wells, “gross income from the property” as used in IRC § 613(c)(1), means the amount for which the taxpayer sells the oil or gas in the immediate vicinity of the well. If the oil or gas is not sold on the premises but is manufactured or converted into a

refined product prior to sale, or is transported from the premises prior to sale, the gross income from the property shall be assumed to be equivalent to the representative market or field price of the oil or gas before conversion or transportation.

Treas. Reg. § 1.613-5 states that the term “taxable income from the property (computed without allowance for depletion)” as used in IRC § 613 and this part, means “gross income from the property” as defined in IRC § 613(c) and Treas. Reg. §§ 1.613-3 and 1.613-4 less allowable deductions (excluding any deduction for depletion), which are attributable to the mining processes, including mineral transportation, with respect to which depletion is claimed. These deductible items include operating expenses, certain selling expenses, administrative and financial overhead, depreciation, taxes deductible under IRC §§ 162 or 164, losses sustained, intangible drilling and development costs, exploration and development expenditures, etc. Expenditures which may be attributable both to the mineral property upon which depletion is claimed and to other activities shall be properly apportioned to such mineral property and to such other activities.

In Rev. Rul. 74-223, 1974-1 C.B. 23, the Service stated, “The term “hedge” means a counterbalancing transaction of a futures contract against an actual purchase or sale of a commodity of against a forward purchase or sale. It is a form of price insurance utilized to avoid the risk of changes in the market.”

Similarly, in Rev. Rul. 72-179, 1972-1 C.B.57, the Service stated, “Such hedges, which eliminate speculative risks due to fluctuations in the market price of cotton and thereby tend to assure ordinary operating profits, are common trade practices and are generally regarded as a form of insurance necessary to conservative business operations. See *Corn Products Refining Company v. Commissioner of Internal Revenue*, 350 U.S. 46 (1955), Ct. D. 1787, C.B. 1955-2-511.”

In *Corn Products Refining Company v. Commissioner*, 350 U.S. 46 (1955), the Supreme Court stated, “We find nothing in this record to support the contention that *Corn Products*’ futures activity was separate and apart from its manufacturing operation. On the contrary, it appears that the transactions were vitally important to the company’s business as a form of insurance against increases in the price of raw corn.”

In *Helvering v. Mountain Producers Corp.*, 303 U.S. 376 (1938), the Supreme Court considered whether a taxpayer's gross income from an oil property used to determine percentage depletion included both cash payments received from the sale of the oil produced at the property and the amount of operating expenses paid by a third party to produce oil at the property. This case interprets a prior statutory provision at §§ 204(c)(2), 234(a)(8) of the Revenue Act of 1926, 44 Stat. 14, 41 and is substantially similar to current § 613(a). The producer claimed that “gross income from the property” should include both the

cash price received for the oil plus the costs of producing the oil paid by the oil producer.

The Supreme Court held “the gross income from the property” which is the basis for the computation of the seller’s depletion allowance for income tax purposes, is the cash price received from the buyer and the expenses of production paid by the buyer should not be added thereto”.

The Supreme Court noted that ‘gross income from the property’ means gross income from oil and gas. The Court noted that if the development operations had failed to produce oil, it would hardly be said that the expense of drilling, borne under contract with another, constituted gross income from the property. The Supreme Court also observed that when oil and gas are produced and sold at the property, the statute does not base percentage depletion on the market value of the production.

In *Guthrie v. United States*, 323 F.2d 143 (6th Cir. 1963) the Sixth Circuit stated, “Had this taxpayer not had the foresight to carry business interruption insurance, its total gross income from mining would have been the amount it received for the coal it was able to mine and market, doing the best it could with its impaired ability. That the taxpayer avoided such consequences by carrying insurance does not make the insurance proceeds a part of the price which the taxpayer received for its coal. We think that these sales proceeds are what constitute ‘gross income from mining.’ We may not extend the statute’s coverage by labeling insurance proceeds as sales proceeds.”

The Court goes on to state, “Congress, however, did not provide for such transposition and to do so would require us to construct a theoretical ‘gross income from mining rather than a real one. In a similar context, the Supreme Court said that the courts cannot fashion a ‘theoretical gross income’ for depletion purposes but are limited to a consideration of the actual sale price. *Helving v. Mountain Producers Corp.*, 303 U.S. 376, 382, 58 S.Ct. 623, 625-626, 82 L.Ed. 907,912.”

- (7) The hedging gains that taxpayers seek to include in “gross income (within the meaning of IRC § 613(a)) from... properties” are hardly derived from mineral sales in the oil patch. These gains come from derivative contracts - swaps, collars, call options, put options, knockout swaps, and basis protection swaps - entered with investment bankers and other financial counterparties. The gains received do not represent the amounts the taxpayer would receive from selling its oil and natural gas production in the field. For instance, the gains on the taxpayer’s natural gas swaps - it’s the most widely used derivative - are based on the amount by which a negotiated fixed price exceeds the market price for natural gas on the settlement date. The hedging gains from the swaps, thus, are more closely associated with correctly identifying the trend of natural gas prices rather than the proceeds a taxpayer would have received selling its natural gas in the oil patch. This is a very legitimate risk management tool but is

hardly “gross income (within the meaning of IRC § 613(a)) from ... properties” as that term has been historically interpreted.

- (8) The term “taxable income from the property” is defined Treas. Reg. § 1.613-5(a) as “gross income from the property” as defined in IRC § 613(c) and Treas. Reg. § 1.613-4 (*i.e.*, gross income from mining) less allowable deductions (excluding any deduction for depletion) which are attributable to the mining processes, including mining transportation, with respect to which depletion is claimed. Because taxable income from the property begins with gross income from mining and allows only those deductions attributable to mineral processes, the obvious intent of the regulations is to narrowly define taxable income from the property just as they narrowly define gross income from mining. Hedging transactions are a form of price insurance. Insurance is not an allowable deduction attributable to the mining processes, within the meaning of Treas. Reg. § 1.613-5(a). Gains or losses from hedging transactions, or “price insurance” are also not taken into account in computing taxable income from the property.

A recent CCA makes some of the same points as above. See CCA 201722028 (stating Treas. Reg. § 1.613-5 does not support that gains or losses should be included in taxable income from the property).

E.3. Exception for Independent Producers and AMT Limitation

- (1) The tax preference amount for IDC from oil and gas wells generally does not apply to corporations that are independent producers (as distinct from integrated oil companies as defined in IRC § 291(b)(4)). IRC § 57(a)(2)(E). However, the benefit of this exception may be limited because the amount by which the preference amount can be reduced cannot exceed 40 percent of AMTI when AMTI is computed as if the exception did not apply. See IRC § 57(a)(2)(E). This rule is illustrated with two examples.

Example: Assume regular taxable income of an independent producer is \$80 and the IDC tax preference amount is \$20 (determined as if exception did not apply). For simplicity there are no other AMT preference amounts or adjustments to consider. Therefore “tentative” AMTI equals \$100 (\$80 plus \$20). Forty percent of this tentative AMTI is \$40. Therefore, the entire IDC tax preference can be eliminated because a \$20 reduction in the preference amount does not cause a reduction in AMTI that exceeds \$40. AMTI is \$80 (\$80 regular taxable income plus \$0 IDC tax preference amount).

Example: Assume regular taxable income of an independent producer is \$40 and the IDC tax preference amount is \$60 (determined as if exception did not apply). For simplicity there are no other AMT preference amounts or adjustments to consider. Therefore, tentative AMTI equals \$100 (\$40 plus \$60). Forty percent of this tentative AMTI is \$40 ($\100×40 percent). If the exception were to apply in full, AMTI would be reduced to \$60 ($\$100 - \40) so the benefit of the exception is limited to \$40. The IDC preference is \$20 ($\$60 - \40) and

AMTI equals \$60 (\$40 regular taxable income plus \$20 IDC tax preference amount).

- (2) CCA 201235010 explains that when AMTI for an independent producer is negative, the IDC preference exception in IRC § 57(a)(2)(E) does not apply. In other words, the IDC tax preference amount should not be reduced at all. Examiners have determined that some independent producers improperly reduced their IDC preference amount, and consequently their AMTI, when their AMTI was negative. The purpose was to increase AMT net operating loss.

E.4. Foreign Tax Credits and Subpart F

- (1) IRC § 907 provides a limitation on the amount of foreign taxes available as a credit under IRC § 901 that were paid or accrued on foreign oil and gas extraction income (FOGEI) and foreign oil related income (FORI). Prior to 2009 tax years, these limitations were computed separately from each other and the limitations for taxes on other foreign income. Effective for 2009 tax years and beyond, the Energy Improvement and Extension Act of 2008 amended IRC § 907 to extend the IRC § 907(a) foreign tax credit limitation for taxes attributable to FOGEI to taxes attributable to FORI. See *also* IRC § 907(f)(4). The combination of FOGEI and FORI is termed “combined foreign oil and gas income”. IRC § 907(b).
- (2) For computing the separate adjusted AMT of a consolidated return member entity, annual reconciliation of FOGEI and FORI carryovers are necessary. See Prop. Reg. § 1.1502-55(h)(6)(iv)(B).
- (3) This provision of the law can be quite complex, and consideration should be given to consulting with an International Foreign Tax Credit Subject Matter Expert or an International Examiner when combined foreign oil and gas income generates foreign oil and gas taxes and when FOGEI or FORI generates foreign tax credits. For tax years beginning before January 1, 2018, IRC § 954(g), Foreign Base Company Oil Related Income, is one type of Subpart F income that could be an issue. A referral of the case to an International Examiner should be considered. Refer to IRM 4.46.3 for international referral criteria and procedures.
- (4) For tax years beginning after December 31, 2017, IRC § 954(g) was repealed by the Tax Cuts and Jobs Act of 2017.
- (5) Examiners should review Exhibit 33: Evaluating Taxpayer Methods of Determining Foreign Oil and Gas Extraction Income (FOGEI) and Foreign Oil Related Income (FORI).

E.5. IRC § 482 Intercompany Services

- (1) Many companies in the oil and gas industry have scientists, engineers, mathematicians, and other highly educated and experienced employees working in the United States, in part, for the benefit of controlled foreign corporations. Income from these intercompany services should be reported on

the associated U.S. tax returns. Issues arise when taxpayers and examiners disagree on the amount of such income and the methodology to determine it.

- (2) Some taxpayers argue that requiring these intercompany services to be reported on a basis other than cost violates the arm's length standard of Treas. Reg. § 1.482-1. Most oil and gas projects are conducted as joint ventures with one party designated to be the operator. Most companies are involved in numerous ventures, acting as operator in some and solely as a joint venture member ("JVM") in others. Historically, operators have generally agreed not to add any profit element to their internal charges to the JVMs for exploration, development and/or production activities. Taxpayers claim that these JVMs are unrelated parties acting at arm's length, and because no profit element exists for similar services rendered to the joint venture, a profit element should not exist for those services rendered to the JVMs by related entities.
- (3) However, examiners have generally determined that the intercompany service transactions between a U.S. company and its CFCs and the service transactions between the operator designated by a Joint Operating Agreement (JOA Operator) and its JVMs are not comparable and do not fall under the comparability provisions of Treas. Reg. § 1.482-1(d). This is because the relationship between the JOA Operator and JVMs is unique and distinguishable from the relationship between a U.S. company and its CFCs. A U.S. company has no participating interest in the CFCs' projects and is generally compensated solely by service fees. By contrast, for transactions involving JVMs, the JOA Operator has a more expansive role than just providing services. The JOA Operator is developing an oil and gas project together with its JVMs and is sharing that project's profits with the JVMs via the production from hydrocarbon extraction. Further, the JOA Operator may enjoy benefits that could not exist with a U.S. company and its CFCs, such as JOA Operator having a greater ability than other JVMs to control total joint venture costs and also shared project funding participation as a member of a joint venture (as opposed to full funding). The provision of services by the JOA Operator to the JVMs is, in the overall picture, ancillary to the main endeavor, which is to develop the hydrocarbon asset in a manner that maximizes the profit for the operator and the JVMs. Thus, because the JOA Operator and the JVMs are co-venturers that jointly benefit from the profits of the project's development and the services-at-cost agreement, it is not comparable to a transaction for services provided by a U.S. company to its CFCs. Depending on the specific facts and circumstances, other distinctions may exist. If this issue or a similar issue is identified during an oil and gas examination, examiners should consider involving an IRC § 482 international subject matter expert, an international examiner, and local Counsel.

E.6. IRC § 199 Domestic Production Deduction

- (1) IRC § 199 provided U.S. taxpayers a deduction for domestic production activities (DPAD) for tax years beginning in 2005. The DPAD is a percentage of

the lesser of the taxpayer's taxable income or qualified production activities income (QPAI) for the taxable year, subject to wage limitations.

- (2) TCJA repealed the IRC § 199 for tax years beginning after 2017. See Exhibit 32: Guidance to LB&I Examiners When An LB&I Taxpayer Files An Amended Return Or Claim For Refund Related To The Repeal of IRC § 199.

E.7. DPAD Issues Specific to the Oil and Gas Industry

- (1) *Expanded Affiliated Group*. For a taxpayer that is a member of an Expanded Affiliated Group (EAG), all members are treated as a single corporation and the deduction is allocated among them based on each member's QPAI, regardless of whether the member has taxable income or loss or W-2 wages for the taxable year. Per Treas. Reg. § 1.199-7(a)(1), an EAG is an affiliated group as defined in IRC § 1504(a), determined by substituting "more than 50 percent" for "at least 80 percent" in each place it appears in IRC § 1504(a) without regard to section 1504(b)(2) and (4). Within an EAG, the activities of its members are attributed to each other. For example, where an integrated EAG extracts natural gas or crude oil, processes or refines that natural gas or crude oil, and sells the resulting items, the EAG is treated as a single corporation whose Domestic Production Gross Receipts (DPGR) are attributable to both extraction and manufacturing. However, when a member of an EAG participates in a joint venture or partnership, the separate pass-through rules generally apply to that member's activities. See Treas. Reg. § 1.199-5 for application of IRC § 199 to pass-through entities. Since joint ventures are common in the oil and gas industry, this could be an area of non-compliance.
- (2) *Qualifying vs. Non-qualifying for Purposes of DPAD*. Generally, the gross receipts generated for the following types of oil and gas activities in the United States qualify as DPGR:

Exploration and production companies engaged in the extraction and production of oil and gas. Gross receipts must be attributable to their working interest in leaseholds and should include only their portion of gross revenues.

Refining and/or petrochemical companies engaged in the refining of oil or manufacturing of petrochemicals.

Manufacturing companies engaged in the manufacturing of tangible personal property such as oil field equipment but only if they properly have the "benefits and burdens" of the manufacturing process. Treas. Reg. § 1.199-3(f)(1).

Construction companies engaged in the construction of U.S. real property. Construction activity means an activity under the two-digit North American Industry Classification System (NAICS) code of 23 and any other NAICS code that relates to the construction of real property such as NAICS code 213111 (drilling oil and gas wells) and NAICS code 213112 (support activities for oil and gas operations). Treas. Reg. § 1.199-3(m)(4) provides that oil and gas platforms are explicitly included in the definition of infrastructure, which is a

qualifying type of real property. Thus, the construction of oil and gas platforms in the U.S. qualify as construction activity DPGR.

Engineering services companies engaged in processing of marine seismic data constitutes engineering services performed in the United States with respect to the construction of real property under IRC § 199(c)(4), but its gross receipts from such services are DPGR only to the extent that such construction activities are within the United States. See *TGS-NOPEC Geophysical Co. & Subsidiaries v. Commissioner*, 155 T.C. 3 (2020).

- (3) Generally, the gross receipts generated for the following types of activities are NOT eligible for inclusion in DPGR:

Gross receipts derived from non-operating mineral interests. For example, royalty income is a non-operating interest income and therefore not includible in DPGR. Treas. Reg. §§ 1.199-3(i)(9); 1.614-2(b).

Gross receipts relating to the sale of products that the taxpayer did not manufacture or refine. For example, gross receipts relating to gasoline sales at a convenience store are not qualifying except in the case where a taxpayer is selling their own refined products. Integrated taxpayers may extract natural gas or crude oil, process or refine that natural gas or crude oil, and sell the resulting items in their own convenience store. Taxpayers may also have purchased crude oil or refined products for resale that they did not extract, manufacture, or refine themselves. These products could be purchased for a variety of reasons, for example to satisfy a long-term supply contract. Examiners may find the gross receipts from these products accounted for as a part of refinery operations or in a marketing/distribution function. Regardless of the reason purchased or the operational area used, these purchased-for-resale products should not be included in DPGR.

Gross receipts relating to transportation and distribution. For example, pipeline companies' gross receipts generated in the transportation of products are generally not includible for purposes of DPGR. However, where an integrated oil company is transporting its own extracted product through its own pipeline to its own refinery, the transportation of such product could be includible in DPGR if all of such activities are included in the same EAG.

Gross receipts attributable to the transmission of pipeline quality gas from a natural gas processing plant to a local distribution company's city-gate (or to another customer) are non-DPGR.

Gross receipts relating to convenience store revenues from non-gasoline sales (for example food and beverages) is not included in DPGR.

Gross receipts related to methane gas extracted from a landfill. Treas. Reg. § 1.199-3(l)(2).

Gross receipts generated from the sale of a leasehold interest, regardless of producing or non-producing. For sale of producing leaseholds, CCA 201208029, released February 24, 2012, addressed the situation where an

exploration and production company sold producing oil and gas properties and treated its entire capital gain as qualifying for IRC § 199. The CCA concluded that gross receipts from the sale of Leasehold Rights are not DPGR under IRC § 199(c)(4)(A)(ii). However, the gross receipts attributable to the sale of the well (and well equipment) may qualify as DPGR. Also, if any capitalized IDC was included in the basis of the Lease, then such amounts should be considered costs related to the construction of the Well and an allocation of such may qualify for DPGR (but not more than the actual capitalized IDC included).

Gross receipts from the sale and/or licensing of processed marine seismic data because it is neither tangible personal property nor a sound recording. See *TGS-NOPEC Geophysical Co. & Subsidiaries v. Commissioner*, 155 T.C. 3 (2020) and IRC § 199(c)(5).

Gross receipts received from a parent company for the processing services of the parent's marine seismic data intended for parent's clients. See *TGS-NOPEC Geophysical Co. & Subsidiaries v. Commissioner*, 155 T.C. 3 (2020).

Gross receipts from combining, mixing, or blending a refined product, e.g., gasoline, with another refined product, e.g., ethanol, dye, or additives, does not meet the "in whole or in significant part" test required by Treas. Reg. § 1.199-3(g). These blending techniques are often referred to as sequential blending or splash blending.

- (4) Examiners should be aware of other types of income that are generally not related to the production of qualified property. For example, service income is not included in DPGR. Also, rental income is generally not included in DPGR unless the property rented was manufactured by the same taxpayer in accordance with other requirements of IRC § 199. If a company claims DPGR on rental of tangible property and it is not performing qualifying construction activities, such as drilling oil and gas wells, an examiner should consider contacting local counsel and the appropriate IRC § 199 subject matter expert.
- (5) **Allocated Expenses for Purposes of QPAI.** The extraction and production of oil and gas have certain unique associated costs. Generally, taxpayers should include all costs associated with the extraction of the crude oil and natural gas or other qualifying activities that can be allocated and apportioned to a class of qualifying income per IRC § 861 and the regulations thereunder. For example, if a qualifying activity is from extraction, the following expenses are some examples of such directly allocable and includible costs:

Depletion (cost and percentage)

Depreciation

Geological and geophysical expenditures

Leasehold abandonments

Intangible Drilling Costs

Dry-hole expenses

- (6) **Oil related Gross Receipts for QPAI.** For tax years 2010 and beyond, the applicable DPAD percentage is 6 percent for oil related QPAI, versus 9 percent for other activities. IRC § 199(d)(9).

“Oil related” QPAI is income attributable to production, refining, processing, transportation, or distribution of oil, or any “primary product” thereof. Total QPAI should be calculated and then the reduction under IRC § 199(d)(9) should be made to the extent there is oil related QPAI. See IRC § 199(d)(9). Oil related QPAI must first qualify under normal rules of QPAI to qualify for 6 percent. Therefore, gross receipts from transportation and distribution do not qualify even if they are oil related. However, the exception for integrated oil companies as explained in 4.41.1.5.4.4.1 (3)(c) still applies.

IRC § 199(d)(9) cross references IRC § 927(a) for definitions of the primary products of oil and gas. The regulations under IRC § 927(a) provide that petrochemicals, medicinal products, insecticides, and alcohols are not considered “primary products” from oil or gas.

- (7) Examination teams should consider analyzing the costs associated with petrochemicals vs. “oil related” QPAI because of possible attempts to shift costs away from non-oil related QPAI (such as petrochemicals) to oil related QPAI to maximize the total DPAD.

- (8) Partnerships.

“Take-in-kind” and “elect-out” (of Subchapter K) partnerships are common in the oil industry. Instead of the partnership selling the oil and gas that it produces, it distributes the oil and gas to its partners for each to sell or use. Without the exception described below, neither the partnership nor the partners would have qualifying DPGR since the partnership did not have third party sales and the partners cannot be attributed the qualifying activities of the partnership. See Treas. § Reg. 1.199-5 for rules regarding partnerships.

A “qualifying in-kind partnership” is defined in Treas. Reg. § 1.199-3(i)(7)(ii) and includes only certain partnerships operating solely in a designated industry - oil and gas, petrochemical, electricity generation, extraction, and processing of minerals. The regulations provide that for “qualifying in-kind partnerships” each partner is treated as performing qualifying activity, such as extracting the property (e.g., oil and gas), that is distributed by the partnership to that partner. See Treas. Reg. § 1.199-9(i)(7). It is important to note that the taxpayer must be a partner in the partnership at the time the partner disposes of the property.

- (9) **Qualified Exchanges.** Energy companies sometimes exchange crude or refined oil products with other energy companies to achieve operational objectives. These arrangements are often made to save transportation costs by exchanging a quantity of product A in location X for a quantity of product A in location Y. The regulations provide a safe harbor that generally addresses the product exchanges above. The safe harbor is allowed for eligible property, which includes oil, natural gas, or petrochemicals, or products derived from oil, natural gas, or petrochemicals, or any other property or product designated by

notice in the Internal Revenue Bulletin. The safe harbor provides, “gross receipts derived by the taxpayer from the sale of eligible property received in an exchange, net of adjustments to account for difference in the eligible property, may be treated as the value of the eligible property received by the taxpayer in the exchange”. Thus, if energy companies C and D enter into a product exchange with a product that would have otherwise qualified as DPGR to both C and D, the fact that the product is ultimately sold to the consumer by the other respective energy company doesn’t disqualify the original products from DPGR treatment for both C and D. Under the safe harbor the taxable exchange is deemed to occur on the date of the sale of the eligible property received in the taxable exchange by the taxpayer, to the extent the sale occurs no later than the last day of the month following the month in which the exchanged eligible property is received by the taxpayer. Treas. Reg. § 1.199-3(i)(1)(iv)(B).

F. Subchapter S Corporations-Elections

- (1) IRC § 1362(a) provides that a small business corporation (defined in IRC § 1361(b)) may elect to be an S corporation, which, generally, is not taxed and thus passes on to the shareholders a pro rata portion of the corporation’s income for which the shareholder is liable for any tax. See *a/so* IRC § 1363. An S corporation has no earnings and profits, except for any attributable to a taxable year prior to 1983 or to a taxable year in which it was a C-corporation. See IRC § 1371(c).

F.1. Dividends-Excess Depletion

- (1) An S corporation that was a C corporation at one time may have accumulated earnings and profits. In general, the earnings and profits of an electing Subchapter S corporation are computed in the same manner as any other corporation. In the computation of earnings and profits of an S corporation, the earnings are reduced by the taxable income because the shareholders are required to include in their gross income. The results of this computation and other adjustments required by IRC § 1368 may cause distributions in excess of the undistributed taxable income to be treated as ordinary dividends in the hands of the shareholder.
- (2) If corporate distributions made in the current year are in excess of current undistributed taxable income, the earnings and profits for the current and prior years should be verified to ensure proper excess depletion is being taken. The adjustments section of *U.S. Income Tax Return for an S Corporations*, Form 1120S, *Analysis of Accumulated Adjustments Account, Shareholders’ Undistributed Taxable Income Previously Taxed, Accumulated Earnings and Profits, and Other Adjustments Account*, Schedule M-2, should be inspected for such excess depletion adjustments.

F.2. Passive Income-Termination

- (1) IRC § 1375(a) imposes a corporate level tax on excess passive income of an S corporation with accumulated earning and profit. Excess net passive income is

passive income in excess of 25 percent of the S corporation's gross receipts, reduced by allowable deductions. IRC § 1375(b)(1). For this purposes, passive income is similar to portfolio income as defined under the passive activity rules, which includes the royalties from oil and gas production payments, royalties, and overriding royalties. This would not include those production payments which do not retain economic interest status and are characterized as loans. Passive income also does not include mineral, oil, and gas royalties, if the income from those royalties would not be treated as personal holding company income under IRC §§ 543(a)(3) and (4) if the taxpayer was a C corporation. Some oil and gas lease bonuses are also considered "passive investment income". If an S corporation has more than three consecutive years of passive investment income in excess of 25 percent of its gross income, the S election is terminated as of first day of the fourth year. See Treas. Reg. § 1.1362-2(c)(2)).

- (2) The examiner should be alert to the types of oil and gas income of electing Subchapter S corporations. The passive investment income relating to the oil and gas business when added to other types of passive investment income could result in an entity level tax or in a termination of the S corporation election.

G. Associations Taxable as Corporations

- (1) The exploration, development, and operations of oil and gas properties are carried on in various business structures and forms, such as co-ownership, joint ventures, and partnerships. It is usually desirable to avoid the corporate form since the intangible drilling and development deductions would benefit only the corporation, and the percentage depletion in excess of cost depletion is added to taxable income in computing earnings and profits. It is normally more desirable to choose an organizational form which will enable the individual taxpayer to benefit the most from the tax deductions in their higher tax brackets. Normally, a partnership or disregarded entity will achieve this result.
- (2) Prior to promulgation of the "Check-the-Box Regulations", the tax classification of business entities followed a complex system of entity classification under what was known as the "Kintner Regulations". These regulations required organizational forms that were not corporations in the legal sense to be classified as corporations for tax purposes if they possessed the following corporate characteristics:
 - Associates
 - An objective to carry on business and divide the gains therefrom
 - Continuity of life
 - Centralization of management
 - Liability for corporate debts limited to corporate property
 - Free transferability of interest

- (3) Effective January 1, 1997, the Check-the-Box regulations replaced the Kintner regulations by simply allowing the taxpayer to check the appropriate box on IRS Form 8832. Treas. Reg. §§ 301.7701-2(b)(1) and (3) through (8) list entities that are “per se” corporations that cannot change their classifications. Under Treas. Reg. § 301.7701-3 entities not listed, such as limited liability companies (LLCs), are “eligible entities” that are treated as partnerships if they have two or more members. If the eligible entity has one member it will be disregarded for federal income tax purposes. An eligible entity can also elect to change its classification.

H. Limited Liability Companies

- (1) The limited liability company (LLC) is a hybrid business structure that combines the benefits of a sole proprietorship or partnership with those of a corporation. Like a corporation, an LLC offers its owners a limited liability shield that protects the business owners’ personal assets from the debts or liabilities of the business. Like a partnership (or sole proprietorship), the LLC may allow all business income and loss to flow through to its owners. For these reasons, the LLC is becoming an increasingly popular format for doing business in most industries, including the oil and gas industry.

IV. Intangible Drilling and Development Cost (IDC)

A. Introduction

- (1) In the case of oil and gas wells, a taxpayer has the 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). *See also United States v. Dakota-Montana Oil Co.*, 288 U.S. 459 (1933). 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.

B. Definition of IDC

- (1) Intangible drilling and development costs is a phrase unique 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(a) list costs which are specifically designated as costs which come within the option to charge to capital or expense. Treas. Reg. § 1.612-4(c)(1) and Rev. Rul. 70-414, 1970-2 CB 132, list costs which are not subject to the option.

C. 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 in the well during the complete payout period. Treas. Reg. § 1.612-4(a); see also Rev. Rul. 70-336 and Rev. Rul. 80-109. 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 and Rev. Rul. 80-109.

D. Election Regarding Intangible Drilling and Development Costs

- (1) IRC § 263(c) provides that 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. Treas. Reg. § 1.612-4(a). The option 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. Treas. Reg. § 1.612-4(d). 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. Treas. Reg. § 1.612-4(e). See Exhibit 4: Useful Examination Techniques - Intangible Drilling and Development Costs.
- (2) Taxpayers that initially elected to expense IDC may alternatively elect to capitalize and amortize all or a part of the IDC, under IRC § 59(e). 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. IRC § 59(e)(1). No other deduction is allowed for IDC to the extent that an election under IRC § 59(e) is made. IRC § 59(e)(3). The amount subject to the IRC § 59(e) election will not be treated as a tax preference item in determining the taxpayer’s AMT. IRC § 59(e)(6). The amount that a taxpayer elects to amortize for a particular taxable year is generally irrevocable. See IRC § 59(e)(4)(B). Examiners should review Treas. Reg. § 1.59-1 for the rules regarding the election.
- (3) See Exhibit 5: Classification of Expenditures in Acquisition, Development, and Operation of Oil and Gas Leases.

D.1. 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 (*i.e.*, 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. 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 (*i.e.*, retailers or refiners of oil and gas). IRC § 291(b)(4). An independent producer is a person who is allowed to compute percentage depletion under the provisions of IRC § 613A(c). See *also* IRC § 613A(d)(2) & (4).

D.2. 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. Treas. Reg. 1.612-4(d)(2); see *also* Rev. Rul. 87-134.
- (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. See Pub. L. No. 99-514, § 411. 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 de-coordinated in 2009.
- (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.

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?

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. TAM 9418002 (May 6, 1994).

- (4) See Rev. Rul. 93-26 for how to account for the unamortized amounts when the underlying property is sold, or the taxpayer ceases to be an integrated producer.

E. 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, 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 this ATG the term “successful well” will be used to describe a well that is a productive 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. IRC § 263(c). 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 TAM 9418002.

- IDC that is currently deductible under IRC § 263(c) or amortized during the tax year under IRC § 291(b) 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. See IRC § 57(a)(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)(2)(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 TAM 9418002.
- (5) Both IDC on successful wells and nonproductive well costs are normally reported in Other Deduction on Line 26 of Form 1120. 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 may be analyzed. Examiners should also look for unusually large figures and for figures that suggest an estimated amount was deducted (e.g., exactly \$1,250,000).

F. 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 the 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:
- **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.
 - **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". 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.

- **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.
- **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 sometime 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. See Section VI.C.5, Placed-in-Service Date of Wells for guidance on the treatment of the cost of tangibles used in the drilling of a well.

G. 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. Treas. Reg. 1.612-4(c). 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. Treas. Reg. 1.612-4(d). Normally, taxpayers will elect to deduct IDC currently.

H. 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.

H.1. 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 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 paid, and the income is taxable in year that it is actually or constructively received. Treas. Reg. §§ 1.461-1(a)(1); 1.446-1(c)(1)(i). The general rules of Section IV.H.4, Agency Relationships, 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, the liability is determined with reasonable accuracy, and economic performance has occurred. Income is taxable when all events have occurred to fix the right to receive income and the amount is determined with reasonable accuracy. Treas. Reg. §§ 1.461-1(a)(2); 1.446-1(c)(1)(ii). Section 451(b) was amended by § 13221 of the Tax Cuts and Jobs Act, Public Law No. 115-97 (131 Stat. 2054), to provide that, for a taxpayer using an accrual method of accounting, the all-events test with respect to any item of gross income (or portion thereof) is not treated as met any later than when the item (or portion thereof) is included in revenue for financial accounting purposes on an applicable financial statement or other financial statement specified by the Secretary. The amendments to IRC § 451(b) do not change the time at which income subject to the all-events test is taken into income for

accrual method taxpayer without an applicable financial statement. 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 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 cannot be used by the accrual basis taxpayer to postpone the deduction until a succeeding year. See IRC § 460. The cost must be deducted in the year paid or incurred, depending on the taxpayer's general method of accounting.
- (5) See Exhibit 36: Accounting Method Changes for an overview of basic accounting method concepts.

H.2. Prepaid Expenses

- (1) For taxpayers using the cash method of accounting, IDC is deductible in the year paid even if the work is performed in the following year as long as the payment is a requirement of a contract. See *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 a cash method taxpayer and paid *Taxpayer B* as provided in the agreement on December 29, 1999. Therefore, *Taxpayer A*, a calendar year taxpayer, deducts IDC on its 1999 tax return.

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

The prepayment is made for a bona fide business purpose.

The prepayment does not substantially distort income.

The drilling contract requires a prepayment of the agreed amount. The prepayment must not be a mere deposit.

The prepayment covers the full 100 percent working interest.

The actual drilling of the well was begun in the first part of the next year.

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 Section IV.H.4, Agency Relationships. 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 method taxpayer. The deduction to the accrual method taxpayer is controlled by the general rules regarding the accrual of any type of expense including the economic performance requirements of IRC § 461(h).

H.3. 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 pre-agreed lump-sum price. Since this type of contract does not separate the tangible equipment cost from the intangible drilling cost (IDC), the agent should make sure that the leasehold and equipment costs are properly capitalized. A common problem occurs when the taxpayer deducts the entire Turnkey price as IDC without regard to the capital equipment items included in the contract. To the accrual basis taxpayer, the accrual of the cost for tangible equipment or IDC should only be made when all the events to fix the liability have been satisfied including the economic performance requirements of IRC § 461(h). Treas. Reg. § 1.461-4. 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 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 may 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.

H.4. 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, an “operator” is 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 one to six months behind in billing 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 method nonoperator will be controlled by the operator’s payment of the expense items. The nonoperator should deduct IDC and operating expenses in the year paid or incurred by the operator even though the nonoperator may reimburse the operator in a later year. Treas. Reg. § 1.461-1(a)(1), *McAdams v. Commissioner*, 15 TC 231 (1950), 52-2 USTC 9373, *aff’d* 198 F. 2d 54 (5th Cir. 1952) (holding that taxpayer should have deducted expenses related to a drilling contract when they were paid by a joint adventurer on taxpayer’s behalf and not when taxpayer repaid the amounts paid on his behalf because the payment by the joint adventurer on taxpayer’s behalf was akin to a loan and expenses paid with loans are deductible in the year in which they are paid.)
- (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. Where material errors are found, they should be corrected.

I. 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 IDC is limited to 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.

I.1. 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. IRC § 263(c); Treas. Reg. § 1.614-2(a). 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. See also *Commissioner v. Idaho Power Co.*, 418 US 1 (1974); TAM 8406006.
- (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 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 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 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 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 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. 73-211.

- (5) Assume the same facts as in the above example except that the payment for the transfer of the 2/3 leasehold interest to *Taxpayer B* and *Taxpayer C* was conditioned on the drilling of a producing well. 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. See Rev. Rul. 75-304.
- (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 [Market Segment Specialization Program training guide on the Oil and Gas Industry](#) is a good starting point, and it identifies 11 revenue rulings that address IDC in the context of sharing arrangements. Rev. Rul. 75-446 and Rev. Rul. 80-109 are additional rulings that deal specifically with carried interest arrangements. The textbook used for Oil and Gas Unit II training should also be consulted.

NOTE: The Market Segment Specialization Program training guide on the Oil and Gas Industry was created in 1996 and is not current in all respects, especially in regard to G&G costs.

I.2. Partnerships

- (1) 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. A partner’s distributive share of income, gain, loss, deduction, or credit shall be determined by the

partnership agreement provided that the allocations under the partnership agreement have substantial economic effect. IRC § 704(a) and (b). Thus, partners may choose how to allocate IDC, through a partnership agreement, provided the allocation of IDC has substantial economic effect. For a complete explanation of “substantial economic effect” see Treas. Reg. § 1.704-1(b) (in its entirety), and *Orrisch v. Commissioner*, 55 TC 395 (1970), and *Allison v. U.S.*, 701 F.2d 933 (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. Treas. Reg. § 1.612-4(d) and (e). 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 important to inspect the partnership agreement for provisions regarding allocations of income, expenses, gains, losses, and credits. Rev. Rul. 77-310 and Rev. Rul. 77-311 address the proper allocation of tax items when there is a change in the partners’ interest in the partnership during the partnership year. 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.

I.3. 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. Treas. Reg. § 1.612-4(a); see also Rev. Rul. 70-657. If the well is not capable of being produced, *Taxpayer B* still must capitalize 50 percent of the IDC to the leasehold basis. Treas. Reg. § 1.612-4(b)(4). *Taxpayer B* may deduct the leasehold cost as a loss in the year the property is abandoned, surrendered, released, or otherwise proven worthless.

- (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.

I.4. 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. 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.

- (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 because 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; Rev. Rul. 71-206; and Rev. Rul. 80-109.

- (5) 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. See Section VIII.E., Carried Interest, for a discussion of carried interest in the context of Sales, Exchanges, and Other Dispositions.

I.5. 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 "cash and carry" arrangement 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:

[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 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 ($\$1000x = \$2500x \times 40$ percent). Sixty percent of *OilCoB*'s expenditure for IDC becomes part of its depletable basis ($\$1500x = \$2500x \times 60$ percent). The regulation similarly affects *OilCoB*'s expenditure of \$500 for equipment. Only 40 percent can be recovered via depreciation ($\$200x = \$500x \times 40$ percent) and 60 percent is added to *OilCoB*'s depletable basis ($\$300x = \$500x \times 60$ 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. See Rev. Rul. 57-40, citing *Virginia Iron Coal & Coke Co v. Commissioner*, 99 F.2d 919 (4th Cir. 1938), cert. denied 307 U.S. 630, 59 S.Ct 833 (1939).

I.6. 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 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 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 1/16 overriding royalty interest the fair market value of the 50 percent of the working interest sold. "A" has two separate properties, the 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 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.

I.7. 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 Section II.C.5, Geological and Geophysical Expenditures.

- (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 the same.

J. 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. Most oil and gas deposits have the following characteristics. First, a deep geologic formation, known as the source rock, generated petroleum due to heat and pressure being applied to buried organic material. Second, the petroleum migrated upward into another formation, known as a reservoir, that contains pores (*i.e.*, has porosity) in which the petroleum is held. The generation and migration of petroleum occur over millions of years. Third, a barrier-type formation, known as a cap rock or a trap, overlies the reservoir and prevents the petroleum from migrating beyond it.
- (2) See Section II.D.6, Acquisition of Government Oil and Gas Leases.
- (3) Offshore development requires structures, equipment, facilities, and wells that are specially designed to operate in a marine environment.

J.1. Offshore Platforms

- (1) Offshore platforms have been used for over 65 years since the first specifically designed structure was installed in the Gulf of Mexico in 1947 in a water depth of 20 feet. The industry is now capable of installing platforms in water depths of several thousand feet. Two of the largest combination drilling and production platforms in the world are in the Gulf of Mexico. The improved techniques of fabrication and erection developed for use on Gulf of Mexico structures have influenced construction worldwide.
- (2) It is not economical to use fixed-jacket platforms to produce oil and gas from water depths greater than 800 feet. Instead, deep water platforms are typically floating and employ either a semi-submersible or "spar" design that requires mooring lines to hold it in place.

J.2. Offshore Drilling Rigs and Mobile Offshore Drilling Units

- (1) Offshore drilling rigs that are installed on platforms are similar to drilling rigs used on land. In many circumstances it is more practical to drill wells from a "Mobile Offshore Drilling Unit" (MODU). Certain MODUs can drill and complete wells in water depths approaching 10,000 feet. The principal types of MODUs are:

Semi-submersible. This MODU is an integrated unit of large dimensions consisting of tubular hulls or pontoons on which are mounted cylindrical columns supporting a fixed upper deck which serves as the drilling platform for the drilling rig. In deep water, the unit is operated from a floating but "semi-submerged" position in which the lower hull assembly is about 40 feet below the water surface. The unit is held in the drilling position by a number of large anchors and heavy chains. In shallow water, the unit can operate as a "semi-submersible" with the lower hull sitting on the bottom. It is not self-propelled and must, therefore, be towed to the drilling location.

Jack-up drilling rig. This MODU has legs which are carried generally above the water when the unit is towed. When in use, the legs are lowered until they reach the bottom and penetrate the ocean floor, thereby permitting the hull to be lifted up by the legs until it becomes stationary above the surface of the water. The hull then serves as a drilling platform. This unit is not self-propelled.

Self-propelled marine drilling rig. Sometimes called a "drillship", this drilling rig is self-propelled. It has crew living quarters which are located on deck behind the drill. Below deck space is entirely taken up with drilling equipment, anchors, and other types of machinery. Modern drill-ships are held in location by thrusters instead of mooring lines.

J.3. Platform Construction Costs

- (1) In general, construction of platforms involves three stages:

Design Phase. During this phase engineers design specifications peculiar to each platform and its planned location.

Land Phase. Prefabrication of as much of the platform as possible occurs on land.

Marine Phase. The platform in its component form is towed by a barge to the drill site, where it is assembled and erected in place.

- (2) The marine phase requires specialized construction equipment such as a combination derrick and pipe laying construction barge. These are constructed in two types. The semi-submersible drilling barge, on which is mounted a heavy lift crane instead of a drilling rig, is used in constructing offshore platforms and other production facilities. The barge also contains equipment necessary for the laying of large diameter pipelines on the ocean floor. The second type of surface floating barge performs the same functions as a semi-submersible

barge but is constructed with a flat bottom and works in a floating, rather than a submerged, position. This unit is likewise not self-propelled.

- (3) The examination of IDC may reveal that costs applicable to platform construction and erection have been included in IDC. The agent should obtain the services of an engineer for assistance in the examination of proper treatment to be awarded platform construction costs.
- (4) An offshore platform may structurally support a drilling rig that is used to drill some or all of the wells that produce to the platform. If the production equipment is located on an adjacent platform, the platform supporting the rig is called a drilling platform. The intangible costs associated with a drilling platform can be deducted as IDC. If the platform supports the rig and contains the production equipment, it is called a “dual purpose” platform. The cost of dual-purpose platforms is discussed in Rev. Rul. 89-56.
- (5) Platforms that do not structurally support a drill rig during the drilling phase of an offshore development are referred to as production-only platforms, or simply production platforms. Generally, the cost of a production platform should be recovered via depreciation.

J.4. Platform Costs Litigation

- (1) In *Exxon Corp. v. U.S.*, 547 F.2d 548 (Ct.Cl. 1976) the court considered costs incurred in the fabrication of “templet type” platforms. The court held that the cost for labor, fuel, repairs, supplies, and hauling incurred in fabricating the standardized components were eligible for IDC option to expense.
- (2) The tax court considered similar issues in *Standard Oil Co. v. Commissioner*, 77 TC 349 (1981), with respect to jacket type platforms, and in *Texaco Inc. v. United States*, 598 F.Supp. 1165 (S.D. Texas 1984) and *Gulf Oil Corp. v. Commissioner*, 87 TC 324 (1986) the courts considered several different types of offshore platforms, which were designed and constructed for use at specific platform locations. The courts found that the platforms were generally not reused, repurposed, or otherwise salvageable and held that the platform or components were not items “ordinarily” considered salvageable.
- (3) In view of these decisions, the Service decided it would no longer follow Rev. Rul. 70-596, which held that all expenditures incurred in the onshore fabrication of offshore drilling and production platforms are ineligible for IDC expense. Rev. Rul. 89-56 held that the deductibility of expenditures related to the onshore fabrication of offshore drilling and production platforms as IDC would be determined on a platform-by-platform basis depending on whether the platform is customized for a specific drill site or salvageable.
- (4) In *LL&E v. Commissioner*, 102 T.C. 21 (1994), the IRS argued that production equipment located on a dual purpose platform that was used in drilling operations for a short period of time was ineligible for IDC expense under the “incident to and necessary” test because the primary purpose of the expenditures was for production and not for well drilling and development. The

Tax Court determined that the “primary purpose test” as argued by the IRS did not exist, and that under the current facts the equipment used in drilling is generally eligible for IDC expense. The IRS acquiesced in the court’s decision. See AOD, IRPO 51,058, *Louisiana Land and Exploration Co. v. Commissioner*, Basis for Cost Depletion, File No. AOD/CC-1995-008 (August 7, 1995).

J.5. Each Platform Analyzed Separately

- (1) Design and fabrication expenditures may be treated as IDC if the evidence shows the following:

The platform in question is incident to and necessary for the drilling of wells even though it is subsequently used for production.

The platform is designed and constructed for use at a specific site.

And platforms of that type are not ordinarily used or otherwise salvaged as a unit.

- (2) When a platform is determined to be eligible for IDC treatment, an analysis of the salvageability of its structural components and subcomponents may be required. For example, the onshore fabrication cost of a standardized and reusable compressor package is not subject to IDC treatment simply because it will be installed on a platform and used in drilling operations but if the package is further integrated into a larger unsalvageable component or the platform itself, both the original fabrication costs and the additional costs involved in the integration will likely qualify for IDC treatment.
- (3) The most significant references applicable to costs of acquiring, transporting, and erecting offshore platforms in connection with oil and gas properties can be found in IRC §§ 263(a) and (c); Treas. Reg. § 1.612-4; Rev. Rul. 89-56; and the decisions in *Exxon Corporation v. United States* and *Louisiana Land and Exploration Co. v. Commissioner*.
- (4) The issue of which particular costs incurred to construct and install offshore platforms are IDC has been ongoing since the 1970’s. The examination of IDC may reveal that costs applicable to platform construction and erection have been included in IDC. Examiners should request engineer assistance in the examination of proper treatment to be awarded platform constructions costs. The Action on Decision in *Louisiana Land and Exploration Co. v. Commissioner* should be reviewed by the engineer.
- (5) With respect to platform dismantlement or well plugging, examiners should also review Section VI.C.11, Future Liabilities for Well Plugging, Platform Dismantlement, and Property Restoration.

J.6. Subsea Wells and Deepwater Platforms

- (1) Significant advances related to MODUs, floating offshore platforms, and “subsea” wells and related infrastructure have permitted the economical production of oil and gas from deep water locations in the 21st century,

especially in the Gulf of Mexico. Modern MODUs can drill and complete wells in water depths approaching 10,000 feet. These wells are extremely expensive to drill and (if successful) to complete. Because intervention in these wells is also very expensive, the operator conducts extensive tests of the mechanical systems of the well before the MODU is released.

- (2) A key characteristic of a subsea well is that its wellhead (aka “Christmas tree”) is located on the seabed (a “wet tree”) instead of being located on an offshore platform (a “dry tree”).
- (3) Subsea flow lines carry production from the subsea well to processing equipment located on a platform. Subsea control cables, which are known as “umbilical lines”, connect the subsea well to a control center located on the platform. The distance between wells and the platform may be 20 miles or more. Technological advances have made it feasible in certain situations to install equipment near the subsea wells such as separators, booster pumps and water injection pumps. Remotely operated underwater vehicles (ROVs) are used to carry out the work of connecting the wet trees, lines, and equipment packages.

J.7. Issues with Subsea Wells and Deepwater Platforms

- (1) The costs of subsea wells and deep-water platforms are usually examined by IRS engineers. One issue involving the long-term use of a MODU illustrates the complexity:

Example: An oil company makes a large payment to a drilling contractor to modify a MODU so that it can carry out certain tasks when drilling wells for the oil company. The oil company contracts to use the modified MODU for a number of years under typical commercial terms. The oil company improperly deducts the payment for modifications as IDC. The payment should be amortized over the life of the contract to use the modified MODU because the contract is an intangible asset. If the oil company acquired equipment to be used for drilling it would recover the cost via depreciation.

- (2) Examination issues involving IDC deductions are summarized as:

Intangible costs, such as those incurred for design, fabrication, and installation of subsea flowlines and umbilicals are often deducted as IDC by taxpayers. Their basic premise is that initial production of a subsea well from the seafloor to the processing equipment located on a platform is analogous to the “flow tests” which were conducted by the operator in the *Louisiana Land and Exploration Co. v. Commissioner* case cited in Section IV.J.5, Each Platform Analyzed Separately. The intangible cost of production equipment used in those flow tests was found to be deductible as IDC. To understand how subsea assets are generally distinguishable from the equipment described in the *Louisiana Land & Exploration* case, and not treated as IDC, it is useful to review why the court reached its conclusion.

In *Louisiana Land and Exploration Co. v. Commissioner*, the flow tests were conducted as part of the completion operation for each well. The wells had been perforated in stages and after each stage was added, the well was flowed (produced) for several hours to determine if the desired production rate was achieved. Only then did the operator shift drilling and completion work to another well. Permanent production equipment had been used to conduct the flow tests. The court determined the subject equipment was incident to and necessary for the development of wells, and therefore was allowable as IDC. The IRS acquiesced and no longer argues that the primary use of equipment in production operations negates the fact that it was used in the development of wells.

IRS engineers have not found a situation where the subsea flowlines, umbilicals and production equipment were utilized in the same manner as the equipment in the *Louisiana Land and Exploration Co. v. Commissioner* case. Rather, the productive capability of modern deep-water wells is normally verified by analyzing data from seismic surveys, numerous well logs, pressure measurements and rock and fluid samples retrieved by sophisticated sampling tools lowered into the well from the MODU. In circumstances where additional confirmation is needed, the operator will produce the well to portable flow test equipment located on the MODU. The well may be temporarily abandoned at this point to allow analysis of the data and design of completion assembly. Regardless, a MODU will be utilized to perform all of the final completion operations, including installation of the subsea tree before leaving the location.

Typically, operators will assign responsibility of a subsea well to a specific internal group depending on the status of the well. Examples of such groups include the drilling and completion team, the flowline and umbilical installation and hookup team, the well and facilities start-up team, and finally the production operations team. The transfer between groups is usually accompanied by certain documents (generally known as pre-commissioning reports, commissioning reports, or "hand-off packages"). Inspections of those documents have shown that the wells are generally viewed by the operator as being "completed" and "ready to produce" prior to initial production to the platform.

A review of operators' press releases and official SEC filings show that prior to initial production of subsea wells it is not uncommon for the wells to be referred to as "successful", for operators to have expended very considerable sums to construct an offshore platform, and for significant quantities of proved reserves to be recorded. The latter is especially significant since reservoirs are only considered proved when production of oil and gas in economic quantities using existing operating methods is known or reasonably certain.

In summary, intangible costs surrounding subsea flowlines, umbilicals, production equipment, and production platforms are not deductible as IDC. The entire cost should be recovered by depreciation starting in the year they are placed in service. When conducting a risk analysis, examiners should consider

the effect of bonus depreciation and be mindful that the issue surrounding these costs and placement of assets often span multiple years.

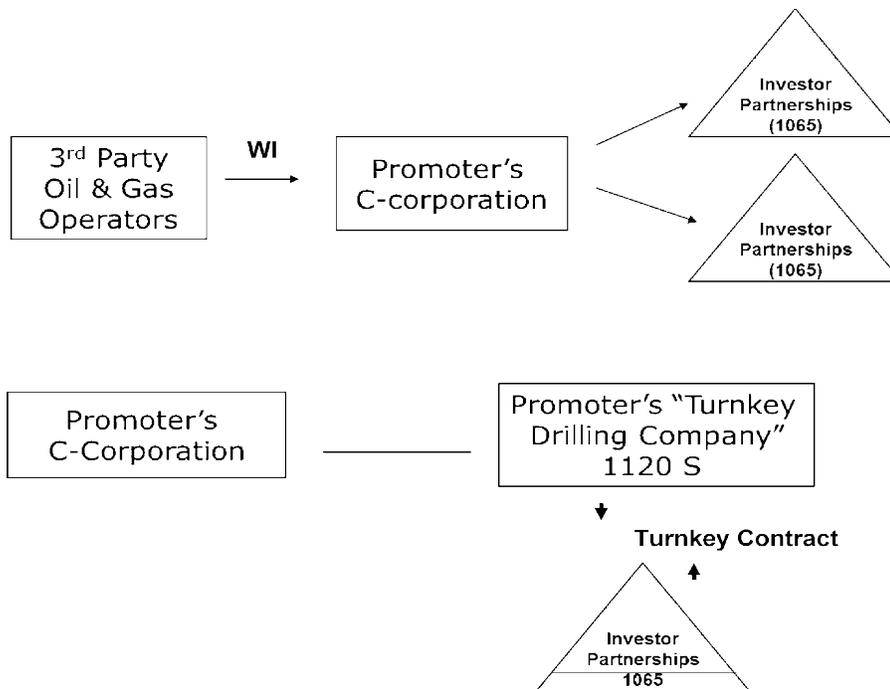
V. Leveraged Oil & Gas Drilling Partnerships

A. Introduction

- (1) The use of partnerships by investors in certain drilling operations to claim losses and current deductions for IDC in amounts that the Service contends exceed both the partnerships' actual IDC and the investors' economic outlay is described below. While not all oil and gas drilling partnerships engage in these abusive transactions, it is an area that calls for a heightened awareness by agents examining these partnerships.
- (2) This section discusses abusive leveraged oil and gas drilling partnerships (LOGDP). Procedures are provided to assist examiners when identifying and handling a LOGDP case.
 - **Note:** Many oil and gas partnerships are not engaged in abusive transactions.
- (3) A leveraged oil and gas drilling partnership is abusive when it is formed by use of promissory notes to artificially inflate the partners' interests in the partnership and generate tax deductions in excess of the actual economic loss. Because of the complex structure of LOGDP, use of a Technical Specialist is highly recommended.
- (4) Examiners should review *Caltex Oil Venture, Caltex Management Corporation, Tax Matters Partner v. Commissioner*, 138 T.C. No. 2 (2012).

B. Partnership Formation and Description

- (1) LOGDP are created by a promoter that forms a partnership or multiple partnerships through which investors participate in oil and gas drilling activities. The abuse occurs at the investor level, and because this type of transaction is typically created as an enterprise group, is detectable only by auditing the entire group of entities.
- (2) The oil and gas drilling activities are conducted through a contractual arrangement between the partnership and promoter-controlled entities. A promoter-controlled upper tier entity is responsible for acquiring working interests in oil and gas wells. A promoter-controlled middle tier entity known as a turnkey drilling company (TDC) is designated as the party responsible for providing subcontracted drilling services for the wells. The general structure of a leveraged oil and gas drilling partnership is graphed below.



C. Description of the LOGDP Transaction and Key Entities

- (1) The LOGDP abusive transaction involves investors contributing cash and signing a promissory note to a partnership that is generally 2-4 times greater than the amount of cash contributed. The promissory note is typically a long-term obligation to be paid at a future date, usually in 15-25 years. The partnership does not loan the investor any money when the note is signed. The transaction involving the Turnkey Contract artificially inflates the partners' interest in the partnership, also known as the partners' "outside basis" and may generate a tax deduction that is several times greater than the cash contributed by the investors.
- (2) The partnership signs a Turnkey Contract with the promoter controlled TDC. The contract is the basis for the IDC deduction. The contract price is close to the total cash and promissory notes contributed by the partners. The cash is immediately paid by the partnership to the TDC. Subsequently, the TDC pays the money to the promoter-controlled upper tier entity. The Turnkey Contract includes a turnkey promissory note for the remaining balance. The turnkey promissory note mirrors the promissory note the investor signs with the partnership. Thus, the partnership has an asset and liability for the same amount.
- (3) The turnkey promissory note is effectively an obligation to make payments to the promoter-controlled TDC for future services; therefore, the payments will be deductible by the partnership as they are made. The turnkey promissory note does not increase the partnership's basis in its assets, nor does it give rise to an immediate deduction or an expense that is properly chargeable to capital. Under this analysis, the turnkey promissory note is not a liability of the

Partnership for IRC § 752 purposes, and therefore investors cannot increase their interests in the partnership by their share of the obligation.

- (4) The IDC deduction is facilitated by the Turnkey Contract, and the related promissory notes. Generally, 50 percent of the cash contributed by the investors and none of the note amounts are spent on drilling operations. The contracts and notes are tools that attempt to artificially create basis and tax deductions for which the investors are not otherwise entitled.
- (5) For further discussion of partnerships, see Section V.F, Partnership Audit Steps.

C.1. Promoter Entities

- (1) **Turnkey Drilling Company.** In the transaction described Section V.C., Description of the LOGDP Transaction and Key Entities, the TDC does not drill the wells or perform any services. The TDC is a cash basis taxpayer and does not recognize the note portion of the contract as income. The TDC functions to provide a layer between the promoter's upper tier entity that actually contracts with third party operators and the partnership. This allows the note portion of the Turnkey Contract to avoid income recognition and taxation by the promoter.
- (2) **Managing Partner.** It is common for the managing partner or Tax Matters Partner (TMP) to be selected by the promoter. The promoter is typically the "de facto" managing partner who sets the amount of the investors' cash contribution and defines terms of the turnkey promissory notes. In addition, the promoter selects all the well sites and determines the Turnkey Contract Price. The managing partner or TMP generally does not contribute cash and does not have any liabilities. Typically, the managing partner has a 1 percent interest in profits and losses. The cash contribution for the managing partner is generally made in a subsequent year by one of the promoter's companies, and in some cases it is never made. Hence, the overall effect of the transactions is that the partnership will have an asset that is slightly greater than the related liability. Although the managing partner is authorized to perform many acts and duties by the partnership agreement, he does not actually perform any duties and his only real function is to be a figurehead for the promoter.
- (3) **Subsequent Year Partnerships.** It is common for the promoter to create several partnerships in subsequent years with the same investors participating in a new partnership in each subsequent year. Examiners should request subsequent tax returns for inspections.

D. Basics of Identifying a LOGDP

- (1) A typical LOGDP will have large IDC deductions on the tax return or on Schedule K1.
- (2) In some cases, the IDC may be included on the Cost of Goods Sold line or other expense lines on the return, so examiners need to review the balance sheet.

- (3) In addition to the large deduction, the balance sheet will report a large receivable and a substantially similar amount as a note payable or other liability. The receivable will compromise most of the assets. Likewise, the related liability will comprise most or all of the total liabilities.
- (4) IDC may be a separately stated item on schedule K or reported in other deductions on page 1 of the Form 1065. It may not be called IDC. In all cases the IDC is the largest of the expenses deducted on the return.
- (5) The following sections are designed as a planning tool to help in the pre-exam and field work portions when auditing LOGDP issues. It is imperative that the revenue agent and petroleum engineer collaborate during the course of the exam.

E. LOGDP Audit Steps

- (1) **Review Books and Records.** Although the agent will have primary responsibility for examining the items below, the documentation revealed from the examination of the books and records will often be important to the other specialties working on the case and used in their audit work (for example, engineer or international agent). Integrating complementary skills and working together as a team has proven more effective in factual development rather than having each specialty work in isolation and then assembling a final product at the end.
- (2) The following describes items helpful in the planning and conduct of the examination. See Exhibits 17 through 25 for recommended IDR's to be issued in LOGDP cases. Additional items for request and review:
 - Partnership Agreement, including all amendments
 - Prospect Agreement
 - Assumption Agreement
 - Subscription Agreement
 - Subscription Note
 - Turnkey Drilling Note
 - Turnkey Drilling Contract
 - Investment proposal or prospectus
 - Other agreements embodied in letters or memoranda
 - Actual drilling contracts and related operating documents
- (3) **Orientation.** Review Exhibit 28: Glossary of Oil and Gas Industry Terms for an overview of engineering terms. Determine if TEFRA or Non-TEFRA (BBA) procedures apply. See IRM 4.31, Pass-through Entity Handbook.

(4) Risk Analysis.

- Attempt to identify promoter and return preparer through conducting a yK-1 analysis. See IRM 5.20.12.7, CKGE and yK-1 Research.
- Review Schedule K-1 for the partners' classification as a general or limited partner.
- Assess the likelihood of material participation. Consider the address of the partner and location of the partnership (*i.e.*, is the partner in a non-oil state or high-tax state?).
- Identify all the partners in the partnership to prioritize interviews. See Exhibit 26: Tax Shelter Partner Listing.
- Consider ordering in status 45 the top five investors' individual tax returns (based on percent ownership).
- Inspect the investor returns for other abusive tax transactions.
- Determine if IDC is deducted on investors' tax returns.
- Prepare an investor matrix to assist in understanding relationships among investors. See Exhibit 26: Tax Shelter Partner Listing.

(5) **Coordination.** It is likely that other taxing authorities have the same entities under audit. Information sharing allows for a more efficient audit. The agent should work with the Manager and Territory Manager to coordinate with these other authorities. Communication with these agencies must be established through proper procedures.

(6) The following steps should be considered:

- Coordinate with other divisions (LB&I or SBSE) if the tax returns are not in your division.
- Establish contact with Governmental Liaison Officer (Disclosure) to obtain information sharing agreements with other taxing authorities (State and Local) where examinations are ongoing.
- Determine if any of the investors, promoter, or other participants are under criminal investigation or investigation by other agencies and tax jurisdictions (*i.e.*, state, city). Transaction Code 914 on AIMS database means active Criminal Investigation.

F. Partnership Audit Steps

(1) Partnership Formation.

- Determine who formed the partnership.

- Determine how the partnership was formed and what was contributed to the partnership in exchange for an interest in the partnership.
 - Determine whether the investors received an investment prospectus or private placement memorandum.
- (2) See Exhibits 17 through 25 for additional items to request and review.
- (3) Examine Books and Records.
- Conduct a functional analysis of the partnership by reviewing actual business operations.
 - Determine if partnership activity reflects that an actual business is being conducted. For example, did the partnership invest in wells that were actually drilled?
 - Determine if books and records are prepared by partnership, promoter, or third party.
 - Determine the manner in which the drilling records are maintained (e.g., by well name, by well operator, or by vendor).
 - Summons should be considered if information is not being received in a timely manner.
- (4) Review Cash Activity.
- Follow the cash (review checks and deposits) to determine where money was spent. This will identify the actual activity of the partnership and may identify other entities to be audited.
 - Look for payments to the promoter or promoter-controlled entities, and payments to related entities.
 - Look for payment of personal expenses and non-business expenses.
 - Determine source of investor capital contribution (e.g., was it their cash or was it borrowed). If cash was borrowed from a party related to promoter, investor may not be at risk.
 - Compare the actual expenses of the partnership to what is included on tax return and the Schedule K-1's.
- (5) **Interview Questions.** Interview the investors and return preparer after review of books and records. Suggested questions are:
- What does the investor know?
 - What is the investor's background?

- How did the investor find out about the partnership?
- Who did the investor talk to?
- What was discussed?
- What documents did the investor receive?
- What information is received from the promoter?
- When did the investor become a partner?
- Is there any interaction with other partners?
- Are there non-tax reasons for investing?
- What are the financial benefits?
- Was anyone compensated?
- Does investor have basis?
- Is investor at risk for notes?
- How are notes paid back?
- What is the extent of the investor's liability for partnership debt?
- Has the investor made any payments on the debt?
- Does the investor list the loans on personal financial statements or loan applications?
- How does the investor intend to pay back the loan?
- Gain understanding of transactions.
- Does transaction occur as it is set up on paper?
- Are the wells actually drilled?
- Who determines which wells to drill?
- Does the partnership have a working interest in the wells?
- Does the transaction have economic reality?
- Is there a basis for assertion of penalties?
- What due diligence was done?
- Can the investor sell his partnership interest?
- Does the investor participate in management?
- Can the investor terminate the partnership?
- If the partnership is terminated, what partnership liabilities did the investor satisfy?

- Is this an abusive transaction?
 - Is investor involved in similar transactions?
- (6) Questions should be tailored to gain a full understanding of the promotion, the persons involved in the promotion, and the investor's motives for participating in the promotion. Ideally, the interviews should be conducted face-to-face, but if time or money constraints limit this, prioritize interviews and/or conduct by written questionnaire.
- **Note:** Investors are considered third-party contacts. See IRM 4.11.57, Examining Officer's Guide, Third Party Contacts.
- (7) **Notes and Other Documentation.** Should the examination of the partnership notes reveal alleged debt, the examiner and engineer need to share information. Much of the revenue agent's findings will impact the engineer's work. These debt instruments may have an accounting impact (*e.g.*, how the notes were recorded) as well as a technical impact (*e.g.*, how notes were used to inflate alleged drilling costs). The examination of the notes should determine:
- If the loans are recourse or non-recourse.
 - How the notes are repaid.
 - If the notes are to a related party.
 - If the loans are from the promoter or promoter-controlled entities.
 - If there is a valid business purpose to the debt (*e.g.*, does the loan leverage the tax deduction).
 - How the loans are actually repaid.
 - Consider at-risk establishment factors.
 - How much (if any) of an investor's money was used to repay the debt.
 - If the repayment plan and period are realistic.
 - Any prior loans that are outstanding by the partners to determine a history of repayments.
 - The validity of any receivables (*e.g.*, subscription notes).
 - If the partners can deduct any loss per IRC § 704 by requesting a partnership basis schedule.
- (8) Consider at-risk limitations and passive activity loss rules. See IRC § 465 and IRC § 469.

G. Engineer Issues and Responsibilities

- (1) An engineer may be called upon as an expert or summary witness regarding oil and gas industry practices and customary deal structures. The engineer's report is a key product. The engineer will perform a functional analysis of the business activities and processes of the partnerships and turnkey drilling companies. The examination will primarily focus on how much money was spent for the actual drilling of any associated oil and gas prospect, and on collecting factual documentation to determine some of the following:
 - The business operations and drilling activity performed,
 - Whether the promoter owns or controls the Turnkey Drilling Company,
 - Whether the promoter formed or controls the partnership,
 - What business function and actual business activity the Turnkey Driller performs,
 - Whether the partnership is entitled to the amount of Intangible Drilling Cost claimed on the return,
 - The extent and dates of drilling activity actually performed, if any,
 - Who or what entity actually performed the drilling activity, and,
 - The reasonableness of the turnkey drilling arrangement.
- (2) Consider hiring an outside expert to assist in determining:
 - whether the turnkey price paid by the partnership was reasonable and constituted an arm's length transaction,
 - whether the terms of the drilling contract were reasonable and customary within industry standards, and
 - whether the promoter-controlled drilling company or the partnership actually undertook the economic risk of drilling wells.
- (3) To address the above, consider as part of the factual development process whether the term Turnkey Driller and Turnkey Drilling Contract refer to the promoter-controlled entity typically styled as a "Turnkey Drilling Company" and the drilling contract between the partnership and that promoter-controlled entity.
 - **Note:** A distinction is made between an actual unrelated third-party turnkey drilling company in the industry and a non-functioning promoter-controlled entity styled as a "Turnkey Drilling Company" that does not perform or contract for the actual drilling.

H. Taxpayer Audit Steps

(1) The following are recommended audit steps:

- Identify the operator of all drilling prospects associated with the partnership.
- Determine if the partnership has a working interest.
- Identify if there are any wells or activity outside of the United States.
- Refer to section IV.H.3, Contract Provisions for discussion of Turnkey Contract issues.
- Compare wells actually drilled to wells only listed in the document that transfers working interests, often identified as a prospect agreement, but not actually drilled. Note any differences and whether any discrepancy is material to the factual development of the case.
- Determine when the wells were actually drilled and whether any related invoices are dated prior to the stated or actual formation of the partnership.
- Review the dates of the invoices for the wells and note any unusual lengths of time after the well was spudded (the date the drilling of the well was first begun).
- Determine whether documents from third parties indicate whether the promoter, a promoter-controlled entity, or its contractor, was the primary or sole contact with the actual well operators.
- Determine whether the division order or joint interest billing statements were sent to promoter, or a promoter-controlled entity, as the named working interest partner for payment.
- Determine whether the promoter, promoter-controlled entity, or the partnership, signed the election letters for well operations.
- For each associated partnership, request executed copies of agreements between the Turnkey Driller and any well servicing companies for activities such as well logging, cementing, casing, perforating, fracturing and maintenance.

I. Promoter Audit Steps

- (1) **Promoter Substance Over Form Issues.** This section is to be worked jointly by the engineer and agent. Read the documents identifying debt and compare the form of transaction to what actually transpired.
- (2) Turnkey Drilling Activity.

- For each associated partnership, verify whether the promoter-controlled Turnkey Driller actually engaged in drilling oil and gas wells with its own equipment and personnel or arranged for others to perform such tasks through written contracts.
- For each associated partnership, request executed agreements between the Turnkey Driller (or any other promoter-controlled entity) and any third-party drilling company contracted to drill wells for the Turnkey Driller. Determine whether the Turnkey Driller arranged for any wells to be drilled for the promoter or a promoter-controlled entity. For each associated partnership, request executed agreements between the Turnkey Driller and any promoter-controlled entities contracted to drill wells for the Turnkey Driller. Note whether the taxpayer or promoter alleges the contracts are verbal and no written contracts exist.
- Use Turnkey Driller Business Characteristics below to determine if the drilling company was actively engaged in the drilling business. Note whether the Turnkey Contract is alleged to provide extraordinary protection against unforeseen financial expenses.
 - Personnel knowledgeable in oil and gas drilling operations.
 - Equipment or other assets to drill oil and gas wells.
 - Written contracts with entities to perform actual drilling operations or well services.
 - Written contracts with entities to arrange for the drilling of oil and gas wells.
- Perform a comparison of the terms of the promoter-controlled company's Turnkey Contract with those that would typically be included in a Turnkey Contract used in the industry. Note the differences between the promoter-controlled company's Turnkey Contract and the model form Turnkey Contract developed by the International Association of Drilling Contractors (available online).

(3) Promoter Involvement.

- Determine whether the promoter was an investor in the partnership. If a contract is between related parties (e.g., promoter-controlled partnership and promoter-controlled Turnkey Driller), are the price, terms, and structure of the contract arm's-length?
- Determine whether the promoter selected the tax matters partner or partnership representative or influenced the

management of the partnership by the tax matters partner or partnership representative.

- Determine whether the promoter controlled the oil and gas income from any producing wells and used such revenue to pay ongoing drilling and operating costs, with any residual being applied to “interest” due on the notes from the investors.
- Identify who determined the turnkey price to charge the partnership. If it was the promoter, determine whether that person had the experience, training, or expertise to develop a reasonable price that is credibly associated with the types of risk associated with drilling operations in the oil and gas industry.

(4) Promissory Notes.

- Determine whether the investors’ promissory notes were used as collateral for payment of a portion of the monetary amount required to drill the wells subject to the partnership agreement.
- Determine whether a turnkey promissory note (between the partnership and the Turnkey Driller) was secured by the investor promissory note (Subscription Note between the partnership and the investor).
- Determine whether the promissory notes were used as a means to inflate the IDC claimed on the return. Compare the amount of IDC actually incurred to the amount claimed on the return and based on the drilling contract price set by the promoter or promoter-controlled Turnkey Driller (view third-party invoices).
- Determine whether the notes are recourse or non-recourse in nature. Is there language in any side agreements that limit the investor’s ability to repay the debt or meet its debt repayment requirement?
- Is the note to be paid out of future oil and gas revenue in whole or in part?
- Does the partnership pledge its assets to secure the note?

J. Penalty Considerations

- (1) The LOGDP is an abusive transaction and penalties such as negligence and valuation misstatement apply.
- (2) Refer to IRM 4.20.1, Examination Collectability, and IRM 4.10.6, Examination of Returns, Penalty Considerations, for guidance.
- (3) The agent determines if the transaction is tax motivated using the following factors:

- Were new investor dollars used to fund prior investments? (Note whether there are elements of a Ponzi scheme.)
- Review transactions for economic reality or substance.
- Would the investment be reasonable without the tax benefits derived?
- Would a reasonable investor invest in this promotion without the tax write-offs?
- Determine the amount of due diligence conducted by each investor.
- Determine if the investor consulted with an independent third party before investing.

K. Preparer/Promoter Considerations

- (1) Consider whether a preparer penalty (IRC § 6694) or a promoter penalty (IRC § 6700) is warranted.
- (2) Consult with a manager or technical specialist to determine if action should be initiated.
- (3) In all cases, the agent must secure managerial approval over any determined penalty under IRC § 6751(b) before assessment, unless such procedures do not apply to the penalty assessed.

VI. Production and Operation of Oil and Gas Properties

A. Introduction

- (1) This section provides guidelines on the production and operation of Oil and Gas Properties.
- (2) Oil and gas production is the ultimate objective of acquiring rights to an oil and gas property. The drilling and completion of a well is necessary before an oil and/or gas property enters its production stage.
- (3) "Production and Operation" means the day-to-day activities necessary for the production and sale of crude oil and/or natural gas. Oil is produced from the wells either by natural pressure in the reservoir or by "artificial lift." Artificial lift usually consists of installing a regular plunger and sucker rod-type pump in the well. However, it can also be accomplished by use of "gas lift" or by hydraulic pump. The operation of an oil and/or gas lease involves the use of lease and well equipment. The operation requires expenditures for and the use of utilities, power, labor, and supplies. Except for the integrated producer, the oil and/or gas produced is usually sold to a larger integrated operator who transports it to their facilities by pipeline. Oil sometimes is sold to a trucking company which resells it to a refiner.

- (4) The accounting and income tax implications involving oil and gas are often complicated by the fact that drilling and completion activities are continuing on the same property that contains production operations.
- (5) An understanding of the typical operation will aid in the discussion of the auditing techniques dealing with each type of interest owner.
- (6) Basically, there are two types of interests in oil and gas properties: operating and nonoperating. The most common types of interests are also described as working interests and royalty interests. See Exhibit 2: Division of the Production From Oil and Gas Property. The distinct difference is that the working interests bear all the operating costs of the property. The royalty interests are free of all operating costs except taxes. There may be several royalty interest owners and working interest owners in a single oil and gas property.
- (7) The owners of the working interest in an oil and gas property will designate one of the working interest owners as the “operator;” or they may designate someone who does not own an interest in the property as the operator. The operator is responsible for the physical operation of the oil and gas wells.
- (8) Typically, the operator will own an interest in the property, but it is not necessary. The operator is usually someone experienced in the operation of oil and gas properties. The operator performs the necessary functions to produce the oil and gas and bills the working interest owners for their proportionate share of the expense, which includes overhead and a profit factor for the operator. Royalty owners do not pay any expense except for production taxes and ad valorem taxes. However, some states allow an operator to bill the royalty owner for its share of certain “post-production” costs such as the cost to compress the gas so that it can be sold to a pipeline purchaser.
- (9) In some cases, the working interest owners will allow the operator to sell their share of the production, deduct their share of the expense of operation, and remit the net amount due to them. Refer to section VI.C.8 - Joint Billing, where, depending on the circumstances, a question may arise as to whether or not this arrangement may be an association taxable as a corporation. Otherwise, the purchaser of the production remits the owner’s share directly and the operator bills the working interest owner for its share of the lease operating expenses.
- (10) Regardless of the method of settlement between the operator and the working interest owners, the operator sends out information, usually in the form of a detailed statement of each item of expense, equipment, and revenue, that relates to the property on a monthly basis. The owner’s share will be computed on this statement. Royalty owners are usually paid directly by the purchaser of the production.
- (11) The typical operation described above is very simplified. Each operator will conduct operations slightly different. Suggestions to help the examiner identify and develop areas are described in the following sections.

B. Sale of Oil and Gas

- (1) Underreporting the proceeds from oil and gas sales is facilitated by the common practice of assigning the income from proven properties as collateral on loans and paying the oil runs directly to the lender. Another problem is the sale of production payments and having a percentage of the oil and gas sales proceeds paid directly to the owner of the production payment. The following sections describe various types of problems that may be encountered and suggested auditing techniques for determining the correct income to be reported from oil and gas sales. See Exhibit 11: Useful Examination Techniques - Oil and Gas Income.

B.1. Income to Royalty Owner

- (1) Income from oil and gas royalties is passive income derived from the landowner's royalty, overriding royalty, or a net profits interest. This type of income bears none of the burden of operations or development except taxes and any "post-production" costs that state law allows an operator to charge a royalty owner in order to make the production marketable, such as for gas compression. Royalty income may be paid by the operator of the property or by the purchaser of the crude oil or gas production. In either event, the royalty owner should receive a statement with the check (usually monthly, but at least periodically) showing the total sales of oil and gas from the property, interest in the property, and the amount of production. An individual taxpayer will normally report royalty income on Schedule E, Supplemental Income and Loss, as rents and royalties or from flow through entities. The taxpayer can have both royalty and working interest income and report both on a Schedule C, Profit or Loss from Business (Sole Proprietorship).
- (2) Since oil and gas royalty income is passive income, it generally is not derived from the conduct of a trade or business and therefore is not subject to self-employment taxes. However, if oil and gas royalty income is an integral part of a trade or business, then the trade or business income, including the royalty income, would be subject to self-employment taxes.
- (3) Oil and gas royalty interests in proven properties make excellent investments and collateral for loans because they require no services or decisions on the part of the owner. Banks and other lenders will gladly accept royalties as collateral for loans because their value can be easily determined, and the income can be assigned and forwarded directly to the bank or other lender from the purchaser of the production.
- (4) One of the most effective auditing techniques for discovering both the underreporting of income from royalties and the sale of a royalty interest is the comparison of both the prior and subsequent years' returns with the year under examination.
- (5) Secure a detailed schedule of the oil and gas properties and note any unusual increases or decreases in the income reported. Determine the reasons for all

unusual increases or decreases. The depletion schedules can be used for this purpose in most instances.

- (6) An underutilized tool for securing information concerning practices of the taxpayer involving the assignment of royalty interest is to question the taxpayer, chief accounting officer, or someone in a position of knowledge whether there have been assignments or sales of royalty interests.
- (7) Request the oil or gas “run tickets” from the operator, on a test basis, to be compared with the income reported in the books.

B.2. Income to Working Interest Owner

- (1) The term “working interest” may also be referred to as an operating interest. The operating or working interest is burdened with all the costs of development, completion, and operation of the property.
- (2) Some confusion may exist between an “operator” (one who physically operates the property) and a “non-operator” (one who merely owns a part of the working interest but is not an operator of the property). There may be several working interest owners, but only one of them will be the “operator.” All of the working interest owners bear their share of the costs of operation. The working interest owners will make all decisions concerning the operation of the property, including the selection of an operator for the property. The selected operator makes all routine operating decisions.
- (3) Oil and gas income of a working interest owner constitutes conduct of a trade or business and therefore is subject to self-employment taxes. It is immaterial that the working interest owner is not the operator or that the working interest percentage owned is small.
- (4) There are a number of problems that can develop and have tax consequences to the working interest owner. In this section, situations relating principally to income will be covered.
- (5) Some indicators on the return that should trigger questions concerning the proper reporting of income are:
 - Leases that continue to operate at a loss and no drilling or development is being done.
 - Income from the property is not representative of the expense being incurred.
 - Large intangible development costs (IDC) are being incurred, but indications exist that the property is being transferred before the income is realized (e.g., transferred to a trust or other family member).
- (6) A proven technique for identifying properties that may not be reporting the proper income is the comparison of detailed operating schedules of both the prior and subsequent years to the year under examination. The reasons for significant changes from year to year should be investigated.

- (7) If a lease is continuing to operate at a loss or the gross revenue is not representative of the costs of operation, there is a possibility that a portion of the lease income has been assigned to a third party, or another person's expenses are being paid.
- (8) To determine the proper amount of income that should be reported from any property, obtain the "run tickets." The run tickets show information identifying the lease and tank involved. A copy of the run ticket is furnished to the operator for each movement of oil from lease tanks. This test should be considered on a sample basis in many examinations. The size of the return and volume of production may influence this decision.
- (9) If there is a need to verify the taxpayer's interest in the property, secure the "lease files." These files should contain the lease agreement, division orders, any assignments, letter agreements, etc., pertaining to the property. These files will vary in content from case to case. It should be noted, however, that taxpayers are protective over the lease files since they represent title to valuable assets, thus care should be exercised in their use.
- (10) If a taxpayer is incurring large intangible development costs on properties to bring them to the production stage and then routinely transferring them to family members or trusts, it may be that this practice can be attacked under IRC § 183 as not being engaged in business for a profit, or under IRC §§ 671 through 679 pertaining to trusts as an assignment of income.

B.3. Gas Balancing Agreements

- (1) Working interest owners will routinely execute a gas balancing agreement to deal with situations where one or more of the parties is unable to take or market its share of production from the underlying property. When imbalances occur, there will be a party that has underproduced and a party that has overproduced. Most balancing agreements dictate that imbalances will be reconciled via future gas production where possible, and cash if need be when the property ceases production.
- (2) Due to a concern that taxpayers were not consistent in their method of reporting income from gas sales when imbalances occurred, the IRS issued regulations in 1994 for joint ventures that elect out of the provisions of sub-chapter K of the Code. See Treas. Reg. § 1.761-2(d). The Regulation mandates that the cumulative gas balancing method be used for tax purposes unless the taxpayer requests, and the IRS consents, to use the annual gas balancing method under IRC § 446(e).
- (3) A key provision of the cumulative gas balancing agreement is that each producer must include in gross income its respective share of sales from all gas produced, including sales of gas taken from another co-producer's share. An overproducer may only claim a deduction in the year in which a balancing payment is made to the under-producer. The under-producer must then recognize income during the year the balancing payment is actually made.

- (4) The depletion deduction generally follows the recognition of income. However, once an overproducer has cumulatively produced more than its share of gas in the reservoir (tip-over), it may not claim depletion on gas that it has taken from under-producers. An exception to this general rule exists under Treas. Reg. § 1.761-2(d)(3)(iii).

B.4. Assignment of Income

- (1) A practice unique in the oil and gas industry is the assignment of income from a property to a third party. This may be done for a variety of reasons and may cover a period of time until a specific amount of income is realized. The assignment of income from the property to be paid over a period shorter than the economic life of the property (a noncontinuing interest) constitutes a production payment, provided that it meets the definition found in Treas. Reg. § 1.636-3(a).
- (2) The Tax Reform Act of 1969 made major changes in the tax treatment of production payments. Effective with respect to production payments created after August 7, 1969, they are to be treated as loans. See Treas. Reg. §§ 1.636-1 and 1.636-4. The only exception is a production payment carved out of a mineral property and pledged for the exploration or development of such property (see Treas. Reg. § 1.636-1(b)). Refer to section II.D.5 - Acquisition of Property by a Production Payment, section VI.B.6 - Production Payments Pledged for Exploration or Development, and section VIII.D - Production Payments, for a discussion of production payments.
- (3) Production proceeds used to pay the owner of a production payment treated as a loan are reportable as revenue for tax purposes by the creator of the production payment. The creator treats the transfer of production proceeds to the owner as payment of principal and interest on a loan. Since the production proceeds relating to the production payment may be forwarded directly from the first purchaser of the production to the owner of the production payment, and never handled by the creator of the production payment, it is difficult to discover the existence of such production payment without special tests being conducted. If a production payment exists, and the property is sold during the year, the sale is encumbered by the existence of the payment, similar to the assumption of a mortgage.
- (4) There are several ways to aid in the discovery of a production payment. If possible and practical, the taxpayer or other responsible official with knowledge of the existence of a production payment should be questioned. Compare detailed schedules of income from oil and gas from prior and subsequent years with the year under examination and secure an explanation of all material increases and decreases in income reported. Inspect the lease files on a selected basis, especially for those properties that have been sold during the year under examination. The contract for the sale of the property should also be inspected to ascertain the existence of an outstanding production payment or the retention of one. The taxpayer's Form 10K, or other report, filed with the

Securities and Exchange Commission may describe production payments if they are material.

- (5) An assignment of income lacking economic substance and resulting in tax avoidance should be questioned. For example, if ownership of an overriding royalty interest (ORRI) is transferred from an entity or person where the ORRI is subject to taxation before the transfer and is not subject to taxation after the transfer, then the transaction may need to be examined. The need for examination would be amplified if the same party benefits from and controls the ORRI before and after the transfer.

B.5. Operator Service Income

- (1) Operators of oil and gas properties are those persons or organizations that physically operate the equipment on the leases that produce the oil and gas income. For this service, operators charge the working interest owners a fee or service charge. Usually, this charge is based on the number of wells involved. The charge may be based on the actual expense of operating the lease by the operator, plus overhead and profit factor. The operator may have an interest in the property, but it is not a requirement.
- (2) Operators are usually experienced in operating oil and gas leases. They often have considerable production of their own in addition to the service income from operation of the oil and gas properties for the account of others. The size and volume of an operator's business will vary from a small proprietorship to a major oil company.
- (3) A unique auditing problem associated with operators develops when they own a part of the working interest in those properties where they are also the operator. Some operators have been known to report the reimbursement from other working interest owners as income from the property and to claim depletion on it. Another abuse resulting from improper accounting is the crediting of lease operating expense accounts with the overhead charges to other working interest owners. This practice sometimes results in increased net income from the property (because the operator "makes a profit" for operating the property of others) and perhaps additional percentage depletion if the net income limitation otherwise would be applicable. This should not be allowed. Examiners should consider whether an adjustment would be material. Operator service income should generally be handled as a separate and distinct business, not a part of an oil and gas lease operation.

B.6. Production Payments Pledged for Exploration or Development

- (1) The general rule is that a production payment carved out of a mineral interest and sold, or retained on the sale of a mineral interest, is treated in the same manner as a loan on the mineral properties. See Treas. Reg. § 1.636-1(a).
- (2) The only exception to this general rule is for a production payment carved out of a mineral property that is pledged for exploration or development of such property. See Treas. Reg. § 1.636-1(b). The Regulations are very specific that

certain conditions must be met before the production payment will qualify for treatment under this exception.

- (3) An expenditure is considered to be “pledged for exploration or development” to the extent it is necessary for ascertaining the existence, location, extent, or quality of any deposit of mineral or is incident to and necessary for the preparation of a deposit for the production of the mineral. See Treas. Reg. § 1.636-1(b)(1). Whether a production payment meets this is a question of fact to be determined in light of all relevant facts and circumstances, including any prior production of mineral from the mineral deposit burdened by the production payment.
- (4) A production payment shall not be treated as carved out for exploration or development to the extent that the consideration for the production payment:
 - Is not pledged for use in the future exploration or development of the property or properties which are burdened by the production payment;
 - May be used for the exploration or development of any other property or for any other purpose than that described above;
 - Does not consist of a binding obligation of the payee of the production payment to provide services, materials, supplies, or equipment for the exploration or development described above; or
 - Does not consist of a binding obligation of the payee of the production payment to pay expenses of the exploration or development described above.

C. Operating Expense

- (1) There are three phases of activity referred to in the oil and gas industry involved in attaining production of minerals:
 - Acquisition of the mineral property
 - Exploration and development, and
 - Operation
- (2) Each of these three phases requires the expenditure of funds, and different tax treatment is accorded each.
 - **Example:** While acquisition costs of a mineral property must be capitalized, the taxpayer may elect to either deduct, amortize, or capitalize IDC incurred during the exploration and development phase. Operating expenses are taken into account in accordance with the taxpayer’s method of accounting. It is important, therefore, to distinguish or categorize the various expenditures that will be encountered in an oil and gas producer’s return.

- (3) Operating expenses of an oil and gas lease will include both direct and indirect expenses and depreciation. It is essential that expenses be segregated by property to determine the taxable income of each if the income derived is subject to percentage depletion.

C.1. Definition of Operating Expense

- (1) An “Operating Expense” is commonly referred to as a “Lease Operating Expense,” and includes the cost of operating and maintaining producing oil and gas leases. Such costs include labor for operating and maintaining the equipment on the lease, repairs and supplies, utilities, automobile and truck expenses, taxes, insurance, and overhead expenses such as bookkeeping, billing costs, and correspondence.

C.2. Operating Expense vs. Intangible Development Costs (IDC) vs. Capital

- (1) Even though most taxpayers elect to currently deduct IDC, it is still necessary to distinguish between operating expenses, IDC, and capital expenditures. Taxpayers who fail to elect the deduction of IDC by claiming such deductions on their return for the taxable year incurred are deemed to capitalize such costs. See Treas. Reg. § 1.612-4(d). Once this election is made, it binds the taxpayer’s treatment of IDC for the taxable year of election and all years thereafter.
- (2) The most comprehensive definition of IDC is found in the Regulations, rulings, and court decisions. IDC is generally defined under the Treas. Reg. § 1.612-4(a) as all expenditures made by an operator for wages, fuel, repairs, hauling, supplies, among other items, that are incident to and necessary for the drilling of wells and the preparation of wells for the production of oil and gas. See Treas. Reg. § 1.612-4(a) for a more comprehensive list of applicable items and examples. The option to capitalize or expense these costs only applies to expenditures for those drilling and developing items which in themselves do not have a salvage value.
- (3) Expenditures by which a taxpayer acquires tangible property ordinarily considered as having a salvage value will not qualify for the option under Treas. Reg. § 1.612-4(a) and must be capitalized. This includes costs to equip the lease for production including the cost of materials used to construct wells on the property, the cost of drilling tools, pipes, casing, tubing, tanks, engines, boilers, and machines. Costs which also must be capitalized include expenditures for wages, fuel, repairs, hauling, and supplies connected to the equipment, facilitates, or structures on the property which are not incident or necessary for the drilling of wells such as structures for storing or treating oil or gas. See Treas. Reg. § 1.612-4(c)(1); Rev. Rul. 70-414 (Jan. 1, 1970).
- (4) Other common costs that must be capitalized include those for installation of flow lines, pipelines, separators, tanks, electric lines, and pumping units and the construction of roads for the purpose of operating the lease. Different

production problems, climatic conditions, or environmental laws may require other types of equipment to bring the property to production. In such a case, the basic rule for the capitalization of expenditures related to equipping leases for the production of oil and gas is similar to the basic rules applicable in any other industry. See IRC § 263(a); Treas. Reg. § 1.263(a)-2(d)

- (5) The rule relating to expenditures that will qualify as IDC under Treas. Reg. § 1.612-4 has developed over the years and has been influenced by several court decisions, some of which are still being decided and could impact the current definition of IDC. See for example the discussion of IDC for offshore platforms in Section J – Offshore Development (Marine Offshore Exploration).
- (6) Despite this, the examiner must be aware that they cannot follow any court decision decided against the Government unless the Commissioner announces his agreement with the decision, or the decision is decided by the United States Supreme Court.
- (7) In the examination of a lease operating expense, expenditures will be found for servicing an existing well, often called “workover” expenses, such as costs incurred in pulling rods from a well, as well as acidizing, fracturing, and cleaning out a well, among other items, all of which are operating expenses. Closely associated with these expenditures are others that have been held to be IDC.
Example: The fracturing of the producing sand with nitroglycerine before being placed in production and the cleaning out of the well have been held to be IDC. See *P-M-K Petroleum Co. v. Commissioner*, 24 B.T.A. 360 (1931); *rev'd by stip.*, 66 F.2d 1009 (8th Cir. 1933). The deepening of an existing well was also held to be IDC. See *Monrovia Oil Co. v. Commissioner*, 28 B.T.A. 335 (1933); *aff'd on other grounds*, 83 F.2d 417 (9th Cir. 1936).
- (8) There is no simple way of distinguishing workover costs that are proper operating costs from those that are IDC. Like with all large expenditures, an inspection of invoices or Authorization For Expenditures (AFE) will reveal the purpose (e.g., routine removal of paraffin from the sucker rods (an operating cost), deepening an existing well (IDC)). Whether the fracturing of a well occurred before or after it was placed in production must be determined from production records or other sources of information that should be in the possession of the taxpayer.
- (9) Before a lot of time is spent on this item, its significance in terms of tax impact should be considered. If the taxpayer has elected to expense IDC and there is no prospect for alternative minimum tax, there is no point in an intensive investigation to distinguish the subtle differences between IDC and operating costs.
- (10) All of the costs relating to the acquisition of an oil and gas lease should be capitalized, but frequently, only the bonus paid to a landowner is capitalized by the taxpayer resulting in all other costs being expensed See § 1.263(a)-2. In every lease acquisition there may be commissions or finder fees involved, abstracting costs, attorney’s fees for title opinions and drafting deeds, and

instruments of conveyance. If the property has production, there may be engineering costs involved in the appraisal of the equipment and study of the oil and gas reserves. Some companies have sufficient leasing activity to warrant employment of a “landman”, a person experienced in mineral leasing activities. The landman’s salary and expenses should be a part of the capitalized lease cost if they can be identified with the acquisition of a particular mineral lease. The same would be true of a “leasing department.” This has been an item of controversy in examinations of some oil producers. Their argument was that the landman and leasing department expenses could not be identified as pertaining to a single lease acquisition, and they considered and rejected many more than they acquired. There is some merit to their argument that not all the costs of operating the leasing department should be allocated to the leases acquired. Therefore, the cost may be allocated between the successful and unsuccessful attempts of acquiring leases on some reasonable basis if an adjustment would be material. See generally, § 1.263(a)-2(f) for capitalization of amounts paid to facilitate the acquisition of real or personal tangible property.

- (11) Equipment costs are usually included in billings from operators or drilling contractors along with other costs such as IDC. The billings will typically itemize all of the different costs involved such as day work, cementing, cleaning out, fuel, etc., and, if equipment is involved, a description of the equipment such as pumping units, flow lines, tanks, etc. The taxpayer’s classification is usually on the face of the billing. It will be necessary to secure the invoices to verify the proper capitalization of equipment costs.
- (12) Taxpayers with a large volume of oil and gas transactions will have an accounting manual that describes how the various expenditures are to be classified. This manual should be studied for accounting policies inconsistent with the Service’s position.
- (13) See Exhibit 10: Items To Consider During Examination for items to consider during preparation of Forms 4318, 4764, 4764-B, and 886A.

C.3. Overhead Costs

- (1) Section 613(a) provides the calculation for the depletion percentage under IRC § 611, which is limited to 100 percent of the taxpayer’s taxable income from the property in the case of oil and gas wells. Treas. Reg. § 1.613-5(a) defines “taxable income from the property” for this purpose as being the gross income from the property as defined in IRC § 613(c), or Treas. Reg. §§ 1.613-3 or 1.613-4, less all allowable deductions (excluding any for depletion) which are attributable to mining processes, including mining transportation, with respect to which depletion is claimed. “Gross income from the property” for oil and gas wells is defined under Treas. Reg. § 1.613-3 as the amount for which the taxpayer sells the oil or gas in the immediate vicinity of the well or the representative market or filed price of oil or gas if the taxpayer manufactures, converts, or transports the product prior to sale. The deductible items included in calculating taxable income from the property consists of operating expenses,

administrative and financial overhead, depreciation, taxes deductible under IRC §§ 162 or 164, losses sustained, and IDC.

- (2) Administrative and financial overhead items include expenses of a general nature. They would include office expenses, accounting costs, rent, administrative salaries, utilities, insurance, interest expense not assignable to a particular lease, and other financing costs.
- (3) Treas. Reg. § 1.613-5(a) provides that “expenditures which are attributable both to the mineral property upon which depletion is claimed and to other activities shall be properly apportioned to the mineral property and other activities. Where a taxpayer has more than one mineral property, deductions which are not directly attributable to a specific mineral property shall be properly apportioned among the several properties.”
- (4) Historically, taxpayers have been allowed some latitude in this area. Businesses are constantly changing, and the percentage of overhead to be apportioned to mineral properties and other activities may vary from year to year.
- (5) There are two generally accepted methods of allocating overhead cost among several mineral properties:
 - Allocating based on the gross income from the property, and
 - Allocating based on the direct expenses of each mineral property (the preferred method). See Exhibit 9: Allocation of Overhead Expenses.
- (6) Usually, it is not to the taxpayer’s advantage to distribute overhead using the same method year after year, and there is a temptation to switch from one method to another. The taxpayer should not be allowed to make this change solely for tax advantages. This practice raises the issue of whether the change in allocation of indirect costs constitutes a change in method of accounting without prior consent of the Commissioner, which is required under IRC § 446(e). However, the Tax Court has previously held that while a taxpayer’s method of allocating overhead costs should remain consistent from year to year, a modification in the allocation method may be warranted where the circumstances justify such a change. See *Occidental Petroleum v. Commissioner*, 55 T.C. 115 (1970). Overhead should also be allocated to drilling costs because of the impact such allocation has on the alternative minimum tax and the calculation of IRC § 1254 recapture regarding IDC.

C.4. Depreciation

- (1) Section 611(a) provides a reasonable allowance for a depreciation deduction of improvements made to oil and gas wells. The deduction allowed under IRC § 611 is determined under IRC § 167. See Treas. Reg. § 1.611-5.
- (2) A depreciation expense should be determined for each mineral property because it is an allowable deduction for determining taxable income of the mineral property under Treas. Reg. § 1.613-5(a).

- (3) The “unit of production” method of calculating depreciation is often used for oil and gas wells, which calculates depreciation based on the number of units produced from the property during its useful life rather than the number of years the property is in use. Treas. Reg. § 1.611-5 provides that, for purposes of IRC § 167, the unit of production method may, under certain circumstances, be considered a reasonable method under IRC § 167(a) and therefore not subject to the limitations of IRC § 167(b). The unit of production method of accounting will be encountered frequently in the examination of tax returns of oil and gas producers.
- (4) Many of the major oil and gas producers have adopted the Modified Accelerated Cost Recovery System (MACRS) available under IRC § 168, which tends to eliminate disputes with the IRS over the useful life and salvage value of assets. There are, however, many oil and gas producers who use the unit of production method.
- (5) In the computation of depreciation under the unit of production method, using the proper oil and gas reserves and a reasonable estimate of salvage value is important. Examiners should verify that estimated salvage value is reflective of the taxpayer’s experience with disposing of retired assets. Joint operating agreements between working interest owners may include an agreed-upon method to determine salvage value when assets such as pumping units are retired, and the operator takes physical and legal possession of them. If a dispute arises, an IRS engineer may need to be consulted.
- (6) Examiners may find that taxpayers are improperly reducing the estimated salvage value of their assets by up to 10 percent of the basis of the assets. While Treas. Regs. §§ 1.167(a)-1 and 1.167(f)-1 suggests this is allowable, the underlying Code provision, IRC § 167(f), was repealed in 1990 and the Regulations have yet to be revised.
- (7) There is sometimes a difference of opinion between the IRS and some taxpayers regarding the proper reserves to be used for computing depreciation using the unit of production method. The only court decision pertaining to this point held that proven, but undrilled, acreage in an oil or gas property was not to be taken into account in determining the reserves to be used in computing depreciation using the unit of production method as they have no relation to the depreciation of equipment used in the production of other property even if such properties are contiguous. *Dulup Oil Co. v. Commissioner*, B.T.A.M. (P-H_ p. 40,412, 1940 WL 10194 (B.T.A.) (Aug. 14, 1940); *rev’d and rem’d on another issue*, 126 F.2d 1019 (5th Cir. 1942).
- (8) There has been no further clarification of this point either in court decisions or rulings. The consensus among IRS oil and gas engineers is that, if the taxpayer accounted for the oil or gas well equipment on each well and used the oil and gas reserves expected to be produced by that well, there would be no objection taken to this practice. By contrast, the total reserves of the mineral property

should be used to depreciate equipment that is common to all of the wells on the mineral property such as separators, heaters, treaters, and tank batteries.

- (9) It should be relatively easy to determine whether a taxpayer is using the unit of production method of depreciation. The instructions for Form 4562, Depreciation and Amortization (Including Information on Listed Property), state that depreciation which is computed by the unit of production method should be entered on Line 15 and a separate sheet with certain information attached.

C.5. Placed-In-Service Date of Wells

- (1) Taxpayers generally claim depreciation deductions beginning in the taxable year the depreciable asset is placed in service. Equipment used in drilling oil and gas wells, including steel casing and associated downhole equipment, must be capitalized. These items are placed in service and subject to depreciation when an oil or gas zone is found and the well is completed and made capable of production. If an oil or gas zone is not found (i.e., a nonproductive well, or dry-hole, was drilled), those assets are not placed in service and are not subject to depreciation. Instead, the adjusted basis of that portion of the equipment left behind in the well is deductible as an abandonment loss under IRC § 165 and Treas. Reg. § 1.165-2. See Rev. Rul. 78-13.
- (2) This Revenue Ruling does not state that equipment such as separators, storage tanks, or a pipeline must be available to accept any oil or gas produced from the well to be considered placed-in-service. Oil and gas wells may stand idle for a period of time while such assets are being constructed by the taxpayer or by third parties, such as a pipeline company, and still be considered to be placed-in-service for depreciation purposes.

C.6. MACRS Class Lives and Recovery Periods

- (1) Refer to Exhibit 27: MACRS Asset Classes Commonly Used in the Petroleum Industry which compiles the MACRS class lives and recovery periods for assets used by companies in the various business segments of the oil and gas industry. Most of the information is derived from Rev. Proc. 87-56.

C.7. Joint Owner Accounting

- (1) Many oil and gas leases are owned and operated by two or more persons as joint owners. The Council of Petroleum Accountants Societies (COPAS) has published a series of bulletins that serve as a standard for accounting practices recommended for the petroleum industry. The [COPAS Bulletins](#) provide a standard method for joint owner accounting, wherein an operator must account for all the income and expenditures to all of the other nonoperating interest owners in the form of a summary billing. The format and content of the billing must be such that the nonoperating interest owners can maintain their records properly from the advice given them by the operator.

C.8. Joint Billing

- (1) Joint billing of the lease operating and development costs by the operator to the other nonoperator interest owners will identify the property and provide a summary of all expenditures and income (unless the purchaser of the production remits direct to the nonoperator interest owner) broken down by capital expenditures, intangibles, and operating expenses. The operator who is also part owner of the working interest will prepare a monthly summary billing of the total lease operating cost and bill the other working interest owners for their share. The accounting entries involved are to credit the various expense accounts involved and debit accounts receivable. This should involve only actual expenses. The overhead or other service charges that are made to the other working interest owners should not be included in the credit to the expense accounts. Instead, it should be credited to a revenue account. Larger taxpayers will generally maintain a separate set of books for joint owner accounting.

C.9. Offset Against Income

- (1) There are different ways by which the revenue from the property will be paid to the various owners. In the usual situation, the purchaser of the production will remit the revenue directly to the working interest owners, royalty interests, overriding royalty interests, and production payment interests. In some cases, the purchaser will remit 100 percent of the revenue to the operator (called a 100 percent division order). It then becomes the operator's obligation to pay each interest owner their share.
- (2) The practice of offset against income can arise in joint owner accounting where the purchaser remits all the working interest owners' share of revenue to the operator. This most generally arises in drilling funds where many of the owners are merely investors.
- (3) The IRS has published rulings (1948-2 C.B. 126 and 1949-1 C.B. 161) approving the concept of joint operation of oil and gas properties under agreements, with the cited characteristics, and not to be classified as an association taxable as a partnership. Refer to the rulings for the specific characteristics; but, in general, if the organization is for investment purposes only, not for an active conduct of a business, there are no joint sales, the joint production, extraction, or use of property, but not for the purpose of selling services or property produced or extracted, must reserve the right to dispose of their shares or share of property, must be able to compute taxable income independently of a partnership income, and all parties must timely file an election under IRC § 761(a) for exclusion, then the organization may not be subject in full or in part to the rules of a partnership under Subchapter K. The concept of these rulings is embodied in IRC § 761(a)(2) and Treas. Reg. § 1.761-2(a)(3). Also see paragraph 7 of section VI - Production and Operation of Oil and Gas Properties.

C.10. Dispersal Account or Oil and Gas Payout Account

- (1) The dispersal account is associated with the revenue received by the operator for the account of the joint interests. This account is treated as a clearing account: as the income is remitted to the other interest owner it should zero out.
- (2) The dispersal account is one that should always be analyzed to determine if it is clearing out or building up a balance. If it is building up a balance, income is likely not being reported by an entity. The most likely prospect is an entity related to the operator. In any event, the reason for the buildup in the account should be ascertained and appropriate action taken.
- (3) The joint operating agreement should be secured in those instances when it appears necessary to know the provisions, rights, and obligations of all parties to the joint operating agreement.
- (4) If the operator is also a promoter and the joint operation is more in the nature of a drilling fund, look for instances where the operator will buy back an interest in the property and charge it off to development costs through the joint operation expense accounts.
- (5) To determine if there exists any carried interest, production payments, or unusual arrangements concerning the allocation of development costs or operating expenses, examine the percentages of income and expense going to the various interests compared to their percentage interest in the property.

C.11. Future Liabilities for Well Plugging, Platform Dismantlement, and Property Restoration

- (1) The operator of an oil well or an offshore platform is obligated by regulations and/or its lease to perform certain tasks when its assets reach the end of their useful lives. When production of a well is depleted, it must be plugged and abandoned. Any earthen pits that contain waste products from drilling or production operations must be either sealed or emptied. Offshore platforms must be removed so they do not become a hazard to navigation. The term “dismantlement, removal and restoration” (DR&R) is often used to encompass these obligations.
- (2) For financial accounting purposes, public companies must estimate the amount of their future DR&R obligations and make appropriate entries on their financial statements. As evidenced by Rev. Rul. 80-182, 1980-2 CB 167, the Service’s long-standing examination position is that “estimated future” DR&R costs may not be deducted (i.e., a deduction is only allowed when the DR&R activity takes place). Although this ruling predates the economic performance rule of IRC § 461(h), it reaches the same result under the all-events test. *See also* Treas. Reg. § 1.461-1(a)(2).
- (3) As background, in the 1970’s and 1980’s the Service’s position was successfully challenged by multiple mining companies. In response, the IRS Office of Appeals created a coordinated settlement position which allowed a

twenty-five-year amortization of estimated DR&R costs for domestic offshore platforms located in water depths of less than 500 feet and placed in service before mid-1984. The Tenth Circuit upheld this amortization period for owners and successors in interest under a closing agreement executed pursuant to this settlement position. In that case, the Court held the amortization of the estimated DR&R liability of the Trans Alaska Pipeline was allowed for its original owners. See *United States v. ConocoPhillips Co.*, 744 F.3d 1199 (10th Cir. 2014). Such settlements generally require the “restoration to income” of previously amortized amounts in two circumstances:

When the taxpayer is relieved of the DR&R liability (e.g., by sale of the asset), or

When DR&R actually takes place and the taxpayer incurs out-of-pocket costs.

- (4) The Service’s position as reflected in Rev. Rul. 80-182 was essentially codified with the enactment of the Economic Performance rules of IRC § 461(h) in 1984. Since DR&R is normally performed by service providers, IRC § 461(h)(2)(A) would permit a deduction only when DR&R services are performed. However, examiners should be aware of the following potential issues:

Taxpayers improperly recovering (over time) estimated DR&R costs via additions to basis for depletion, depreciation, or amortization. Examiners should make sure the taxpayer has reversed all such deductions or basis additions that were included or expensed for financial accounting purposes.

Taxpayers failing to properly “restore to income” any previously amortized amounts at the time the DR&R actually occurs or when the taxpayer is relieved of the liability.

Deducting the full amount of premiums paid for surety bonds when part of the premium is essentially a refundable deposit for future DR&R costs. Surety bonds are often required for “thinly capitalized” oil companies that install offshore platforms in federal waters. Annual insurance premiums are generally deductible. However, some surety arrangements consist of both a surety policy and an escrow account. Contributions to an escrow account are generally not deductible because they are refundable if the policy is cancelled.

“Guarantee fees” paid to a foreign parent. The U.S. Department of Interior will generally impose the DR&R obligation on the original lessor of federal land whenever a sublessor fails to perform its obligation. Consequently, the transferor of a federal oil and gas lease will often require (by contractual obligation) the transferee to maintain adequate financial reserves to perform DR&R, or to obtain the guarantee of a parent corporation. Examiners may find U.S. taxpayers improperly deducting “fees” paid to their foreign parent to “guarantee” performance of DR&R on behalf of its subsidiary. Such payment should not be allowed as a deduction because in substance it represents a mere deposit of funds with the parent corporation.

- (5) Economic performance rules for liabilities that are assumed in the sale of a trade or business are specifically addressed by Treas. Reg. § 1.461-4(d)(5). If the buyer expressly assumes a liability arising out of the trade or business that the taxpayer but for the economic performance requirement would have been entitled to incur as of the date of the sale, economic performance with respect to that liability occurs as the amount of the liability is properly included in the amount realized by the taxpayer upon the sale. Refer to Treas. Reg. § 1.1001-2 for the rules regarding the inclusion of income derived from discharged liabilities in a sale or exchange. If an examiner determines that a taxpayer utilized this regulation in the context of selling assets subject to future DR&R liabilities, then the liabilities should be reviewed and discussed with Local Counsel or a Subject Matter Expert.

D. Secondary and Tertiary Recovery Methods

- (1) The production of crude oil from a reservoir is often viewed as occurring via recovery methods that occur in phases (e.g., primary, secondary, and tertiary recovery methods).
- (2) Primary recovery relies on the inherent energy in the reservoir to allow wells to produce fluids in the reservoir to the surface, and pumps to lift fluids from those wells when the reservoir energy is insufficient.
- (3) Secondary recovery methods generally involve the injection of water or natural gas into the reservoir to increase or maintain its pressure, or to displace oil towards producing wells without causing significant chemical or physical changes to the oil.
- (4) Tertiary recovery methods generally cause a significant chemical or physical change to the oil (other than just an increase in pressure). An example is the introduction of heat into the reservoir to lower the viscosity (thickness) of the oil which in turn allows it to flow more readily towards producing wells. “Tertiary recovery” is a term that has been used in the industry for several decades. Section 193 defines “qualified tertiary recovery methods” specific to incentives in the Code as:
- (5) Any method described in 10 CFR § 212.78(c)(1) through (9) of the June 1979 energy regulations (as defined by IRC § 4996(b)(8)(C) as in effect before its repeal), or
- (6) Any other method to provide tertiary enhanced recovery which is approved by the Secretary for purposes of IRC § 193.
- (7) The methods described in former 10 CFR § 212.78(c)(1) through (9) include:
 - Miscible fluid displacement;
 - Steam drive injection;
 - Microemulsion or micellar/emulsion;
 - In situ combustion;

- Polymer augmented waterflooding;
 - Cyclic steam injection;
 - Alkaline (or caustic) flooding;
 - Carbon dioxide augmented waterflooding; and
- (8) Immiscible carbon dioxide displacement. The use of horizontal drilling in conjunction with reservoir fracturing has become very common in recent years and has resulted in very significant production of oil and natural gas. However, these are drilling and completion techniques that allow the production of oil and gas via primary and other recovery methods, and not tertiary recovery methods.
- (9) Secondary and tertiary recovery methods of oil recovery may be instituted at any time during the economic life of an oil field. The implementation of such methods usually occurs after the entire field has been developed and primary recovery has occurred for a number of years. Information gained during development and production operations is very important in optimizing the design of subsequent recovery methods.
- (10) A successful secondary or tertiary recovery program involves a plan wherein water, gas, or some other fluid is injected into the oil-bearing formations which force the oil into the bore holes in order that it may be pumped out. This may involve the drilling of injection wells and additional oil wells. The injection wells may be located on the perimeter of the oil field or interspersed in a pattern throughout the oil field to drive the oil through the formation to the oil wells. Because of the need for a plan involving an entire field, several owners may be involved. Hearings before the state conservation commission are likely to be required to gain approval of the plan. Unitization of ownership interests will also likely be required.

D.1. Waterfloods and Gas Pressure Maintenance

- (1) The most common method of secondary recovery is water flooding. Waterfloods will usually require the drilling of additional oil wells and injection wells that will fit a pattern designed to produce the maximum amount of oil from the property. The drilling costs of both the injection and oil wells are deductible as IDC if the taxpayer has made the proper election under IRC § 263(c). Tangible equipment is required to be capitalized, however, and depreciated in the same manner as if the wells were being drilled for primary production. See Treas. Reg. 1.612-4(c)(1); Rev. Rul. 78-13.
- (2) A common method of water flooding used is the “five-spot pattern” where one producing well will remain in the center of four water injection wells. Usually some of the producing wells will be converted to water injection wells.
- (3) Another common secondary recovery method is the injection of natural gas into an oil reservoir to maintain reservoir pressure which in turn improves oil

recovery. See section VII.D.7, Unitization for potential issues with such methods.

D.2. Operating Costs

- (1) Operating costs are usually somewhat higher when secondary recovery methods are employed because of the added expense of injecting the water or gas into the formation under pressure requiring the operation of pumps, compressors and other equipment using energy. The water that is pumped out with the oil must also be handled. However, the operating expenses are deductible in the same manner as those incurred in the primary production.

D.3. Water Supply Wells

- (1) Water supply wells that are drilled for the principal purpose of furnishing a water supply for the injection wells are required to be capitalized and depreciated. Wells that are drilled for the principal purpose of supplying water used in the drilling of oil and gas wells, however, come within the option of IRC § 263(c) to charge to expense IDC. See Treas. Reg. 1.612-4.

D.4. Water Injection Wells

- (1) Water injection wells may be new wells drilled to satisfy a pattern needed for the waterflood plan, or they may be converted from existing oil wells. In either case, taxpayers may elect to expense these costs as IDC under the option contained in IRC § 263(c) and Treas. Reg. § 1.612-4. In *Page Oil Co. v. Commissioner*, the court first affirmed this view regarding water injection wells drilled before the production of oil. 41 B.T.A. 952 (1940), *nonacq. on another issue*, 1940-2 C.B. 13, *aff'd*, 129 F.2d 748 (2d Cir. 1942). This position was subsequently affirmed by the Service, first in certain circumstances established in Rev. Rul. 69-583, 1969-2 C.B. 41, and subsequently in general in GCM 39619 (March 17, 1987) and TAM 8728004 (March 18, 1987).

D.5. Saltwater Disposal Wells

- (1) Saltwater disposal wells are required by most state regulatory agencies if salt water is produced with the oil. It must be separated from the oil and disposed of by being injected into a saltwater disposal well. Most states have strict rules concerning the disposal of salt water and require operators to agree to certain specifications for the drilling and equipping of saltwater disposal wells.
- (2) The problems encountered in auditing a waterflood secondary recovery operation are that certain drilling costs do not come within the option to charge to expense the IDC. The drilling of saltwater disposal wells and water supply wells, if drilled for the principal purpose of acquiring a water supply for injection into the producing formation, does not come within the option under IRC § 263(c). See Rev. Rul. 70-414, 1970-2 CB 132. But the taxpayer's records and vendor's invoices may merely reflect drilling expenses without referring to what kind of well is being drilled. Thus, whether the option under IRC § 263(c) is available for these expenses is not easily determined.

- (3) There are two resources that may help the examiner identify or discover whether a water supply well or saltwater disposal well has been drilled. First, if the taxpayer is an operator, an oil field map identifies the location and number of all wells. Usually, freshwater wells and saltwater disposal wells can be identified from such a map. Second, most state regulatory agencies require a permit to be secured before the well can be staked and drilling started in which case the operator would have a copy of the application, giving all of the information needed for a determination of the type of well drilled.
- (4) It is not unusual for a taxpayer to convert an old oil well or dry-hole to a saltwater disposal well, and, so long as the taxpayer's stated intentions correspond to its actions, such drilling costs may be expensed as IDC. However, there are usually additional drilling and completion costs associated with the conversion of an oil well or dry-hole to a saltwater disposal well. These may be identified by a review of the application with the state regulatory agency for the conversion. The application will list the numerous specifications and work that will be done to comply with the state's specifications for the conversion.

D.6. Other Costs

- (1) The tax treatment of all types of secondary and tertiary recovery methods is virtually the same. One common characteristic is that all methods require specialized equipment such as pumps, tanks, boilers, high pressure wellhead equipment, filters, etc. This type of tangible equipment must be capitalized and depreciated. The expense of operating the secondary or tertiary recovery system such as power, utilities, chemicals, repairs, labor, depreciation, etc., are deductible as part of the lease operating expense.
- (2) There are specific rules in IRC § 193 for "qualified tertiary injectant expenses." Section 193(a) requires that a deduction for the taxable year of an amount equal to the qualified tertiary injectant expenses of the tertiary injectants injected during such year. For purposes of IRC § 193, the term "qualified tertiary injectant expenses" means any cost paid or incurred during the taxable year (whether or not chargeable to capital account) for any tertiary injectant (other than a hydrocarbon injectant, which is recoverable) which is used as a part of a tertiary recovery method. The term "hydrocarbon injectant" includes natural gas, crude oil, and any other injectant which is comprised of more than an insignificant amount of natural gas or crude oil. Refer to Treas. Reg. § 1.193-1 before making a tax decision with respect to hydrocarbon injectants.
- (3) Examiners should be aware that some taxpayers have improperly claimed the capital cost of tangible equipment which handles tertiary injectants (such as carbon dioxide pipelines) is currently deductible under IRC § 193 as a qualified tertiary injectant expense. Such position is primarily based on the language found in Rev. Rul. 2003-82, 2003-2 C.B. 125, which was issued with respect to the IRC § 43 Enhanced Oil Recovery tax credit. That ruling states that, for purposes of IRC § 43(c)(1)(C), the definition of "qualified tertiary injectant

expenses” includes expenditures related to the use of a tertiary injectant as well as expenditures related to the acquisition (whether produced or acquired by purchase) of the tertiary injectant. The ruling does not, however, state or suggest that tangible equipment costs are considered qualified tertiary injectant expenses under IRC § 193. See PLR 201117028.

E. IRC § 43 Credit - Enhanced Oil Recovery

- (1) IRC § 43 was enacted in 1990 to provide an investment credit for certain costs paid or incurred with respect to qualified Enhanced Oil Recovery (EOR) projects. The amount of the credit is generally equal to 15 percent of qualified expenditures made by the taxpayer and becomes part of the general business credit. The credit is claimed on Form 8830. Only an owner of an operating mineral interest may claim the EOR credit.
- (2) The EOR credit has a "phase out" provision that will reduce or eliminate the rate of the credit whenever oil prices in the U.S. rise above \$28 per barrel and is completely phased out when oil prices exceed this amount by \$6 or more (both figures are adjusted for inflation after 1990). The Service issues an annual Notice announcing the inflation adjustment factor and phase-out amount for each tax year. The phase-out amounts for prior tax years have occurred as follows:
 - For the taxable years beginning in the 1991 through 2005 calendar years, there was no phase out and the full 15% was in effect.
 - For the taxable years beginning in the 2006 through 2015 calendar years, there was a 100% phase-out and no credit was allowed.
 - For the taxable years beginning in the 2016 and 2017 calendar years, there is no phase out and the full 15% is in effect.
 - For the taxable years beginning in the 2018 calendar year, there is a slight phase out and the rate of credit is 13.931%.
 - For the taxable years beginning in the 2019 and 2020 calendar years, there is a 100% phase-out and no credit is allowed.
 - For the taxable years beginning in the 2021 calendar year, there is no phase out and the full 15% is in effect.
 - See Notice 2021-47, 2021-32 IRB 269, for a detailed explanation of how the 2021 credit rate was determined and for a listing of the credit rate for prior years.
- (3) Generally, the EOR credit is only available for projects that employ certain tertiary recovery methods, unless the IRS approves an additional recovery method via a revenue ruling or a private letter ruling. The projects must be located within the U.S. and commence after December 31, 1990. There is an

exception, however, for “significant expansions” of projects that began before 1991. See Treas. Reg. § 1.43-2(d).

- (4) If a project for which the first injection of liquids, gases, or other matter occurred before January 1, 1991, is significantly expanded after December 31, 1990, the expansion is treated as a separate project for which the first injection of liquids, gases, or other matter occurs after December 31, 1990. Treas. Reg. § 1.43-2(d)(1). Treas. Reg. § 1.43-2(d) provides for three types of significant expansion projects:
- Injection into substantially unaffected reservoir volume. Treas. Reg. § 1.43-2(d)(2);
 - Restart of terminated projects. Treas. Reg. § 1.43-2(d)(3);
 - Change in tertiary recovery method. Treas. Reg. § 1.43-2(d)(4); and
 - Several examples are provided in Treas. Reg. § 1.43-2(d)(5).
- (5) Starting in 2005 the EOR credit was extended to costs to construct a gas treatment plant capable of processing certain Alaska natural gas for transportation through a pipeline with a capacity of at least two trillion British thermal unit (Btu) of natural gas per day. To qualify, the gas treatment plant must also produce carbon dioxide which is injected into a hydrocarbon-bearing geological formation.
- (6) A self-certification process is mandated by the statute under IRC § 43(c)(2)(B) and Treas. Reg. § 1.43-3. The operator of each EOR project (or its designee) must file a certification from a registered petroleum engineer stating that the project meets certain criteria. Afterwards, a continuing certification is filed annually. IRS Form 8830 directs taxpayers to file all certifications with the LB&I Enterprise Practice Area in Houston, Texas by the due date of the operator’s or designated owner’s federal income tax return. The petroleum technical subject matter experts are responsible for maintaining the inventory of the certifications. When a certification appears to lack information required by the regulations, the technical subject matter experts will notify the examination team for taxpayers currently under audit and will directly contact other taxpayers.
- (7) The expenditures which will qualify for the IRC § 43 tax credit generally consist of tertiary injectant expenses, tangible property costs, and IDC. For purposes of the EOR credit, tertiary injectant expenses are defined under IRC § 193(b) and must be deductible during the taxable year under any code section. Refer to Rev. Rul. 2003-82, 2003-2 CB 125. A frequent issue is determining the correct amount of tertiary injectant expense when taxpayers self-produce their own injectant and recycle it for reuse when it was produced alongside the crude oil.
- (8) The at-risk limitation rules of IRC § 465 apply. On a year-by-year basis taxpayers may decide whether to claim the credit. When the credit is claimed,

the taxpayer must reduce its deductions and/or basis of those items which comprise the qualified expenditures by the amount of the credit.

- (9) Many EOR projects are operated by joint ventures and the operator will frequently notify the non-operators as to the annual expenditures for qualified costs. When an examiner has reviewed a project in sufficient detail to determine the merits of the project and the associated major expenditures, the following steps should be taken:
- Secure the identity of the operator, each working interest owner, and the working interest percentage of all parties.
 - Request a copy of any information letter supplied to or from the operator regarding the amount of qualified costs.
 - Provide the forgoing information and a synopsis of the examiner's determination to the petroleum technical subject matter experts who will forward the examiner's determination to other affected examination teams for their consideration.
- (10) There are two timing issues that arise when claiming the EOR credit, given the different phase-out rates from one year to the next:
- Taxpayers using a fiscal taxable year must use the credit rate associated with the calendar year in which their fiscal year begins. For example, for taxable fiscal years beginning in calendar year 2018, the credit rate of 13.931% is applied to all qualified expenditures regardless of whether the cost was paid or incurred in months of calendar year 2019 that were part of the taxpayer's 2018 taxable year.
 - Costs paid or incurred in one tax year for depreciable property not placed in service until the following tax year are properly included for the EOR credit in the tax year in which the costs were paid or incurred, not the tax year in which depreciation begins.
- (11) Because of the workings of the General Business Credit carryforward under IRC § 38, a review of credits used to offset tax in a given year is required to determine if the EOR credit issue is present. The EOR credit may not have been examined for the tax year earned if it did not offset tax. Examiners should consult with the case manager about examining EOR credit claimed in a prior year but carried forward and used to offset tax in the year under examination.
- (12) The EOR tax credit is highly factual, and the amount of the credit is based upon both engineering judgment and reasonable allocation methods. Agents should consider requesting the services of a petroleum engineer.

F. IRC § 45Q Credit - Sequestration of Carbon Dioxide in Enhanced Oil or Natural Gas Project

- (1) IRC § 45Q is a component of the General Business Credit. See IRC § 38(b)(29).
- (2) Of interest to oil and gas examiners, IRC § 45Q provides a tax credit for qualified carbon oxide that is captured at a qualified facility and disposed of in secure geological storage (sequestered), including qualified carbon oxide used as a tertiary injectant in qualified enhanced oil or natural gas recovery projects. The amount of credit allowed under IRC § 45Q depends on when the carbon capture equipment was placed in service and how the taxpayer utilizes the qualified carbon oxide captured.
- (3) Final regulations for IRC § 45Q were issued on January 15, 2021 and apply to tax years beginning on or after January 13, 2021. See T.D. 9944, 86 FR 4760; Treas. Reg. §§ 1.45Q-0 through 5. For taxable years beginning on or after January 1, 2018, however, taxpayers may elect to apply either the rules of these final regulations, or those found in the Notice of Proposed Rulemaking at 85 FR 34050-01 (June 2, 2020). See Treas. Reg. § 1.45Q-1(i); Instructions to Form 8933, Carbon Oxide Sequestration Credit (2021).
- (4) If a taxpayer elected to apply the TD or NPRM, examiners should verify the taxpayer followed them in their entirety. Oil and gas examiners should focus on the requirements for a binding written contract and secure geologic storage.

G. IRC §45K Credit - Nonconventional Source Fuels

- (1) Section § 45K (renumbered from IRC § 29) and made part of the General Business Credit with the enactment of Tax Incentives Act of 2005, see IRC § 38(b)(22), authorizes an income tax credit for the production of certain non-conventional fuels. The credit under IRC § 45K is generally equal to \$3.00 multiplied by the number of “barrel-of-oil equivalent” of qualified fuels that is produced and sold by the taxpayer to unrelated persons. When a fuel-producing property is owned by more than one taxpayer, production is generally allocated based upon each taxpayer’s interest in gross sales. Treas. Reg. § 1.761-2(d) provides specific rules for gas producers that produce natural gas under joint operating agreements.
- (2) Qualified fuels include:
 - Oil produced from shale and tar sands;
 - Gas produced from geopressured brine, Devonian shale, coal seams, or a tight formation, or biomass; and
 - Liquid, gaseous and solid synthetic fuels from coal (including lignite), including such fuels when used as feedstocks.
- (3) The credit for these fuels has both a drilling window (generally from January 1, 1980 through December 31, 1992) and a production window (from January 1,

1980 through December 31, 2002). Thus, except for production in 2002 for which a taxpayer claims a credit, this issue no longer exists after 2002.

H. IRC § 45I Credit - Marginal Wells

- (1) Section 45I provides a tax credit for producing oil and gas from marginal wells. The credit under IRC § 45I is also a part of the General Business Credit under IRC § 38(b)(19). The amount of credit under IRC § 45I is equal to the product of the "credit amount" and the qualified crude oil and natural gas production attributable to the taxpayer. The "credit amounts" (i.e., rates of credit) are \$3 per barrel of qualified crude oil production and 50 cents per 1,000 cubic feet (MCF) of qualified natural gas production. These credit amounts are subject to a "phase out" equal to the ratio of the excess (if any) of the applicable reference price over \$15 (\$1.67 for qualified natural gas production) to \$3 (0.33 for qualified natural gas production). The amount of the phase out is adjusted for inflation for tax years beginning in a calendar year after 2005.
- (2) The Service issues an annual notice with the credit rates, reference prices, and inflation adjustments for used for calculating the credit under IRC § 45I. The credit rate for crude oil has always been zero due to high oil prices. For taxable years beginning in calendar years 2016, 2017, 2019 and 2020 the credit rate for natural gas has been above zero. See Notice 2021-34, IRB 2021-23 (June 7, 2021) for the most recent notice.
- (3) In case of production from a qualified marginal well which is also eligible for the Nonconventional Fuel Source Credit allowed under IRC § 45K, the taxpayer can claim the IRC § 45I credit only if it elects to not claim the IRC § 45K credit with respect to the well. See IRC § 45I(d)(3).

Marginal Well Credit for Natural Gas Production:

- (1) Section 45I(a), as it relates to qualified natural gas production, provides that the Marginal Well Credit (MWC) for any taxable year is an amount equal to the product of (1) the credit amount and (2) the qualified natural gas production that is attributable to the taxpayer. The credit amount is stated in terms of cents per thousand cubic feet (MCF) of natural gas.
- (2) Section 45I(c)(1) provides that "qualified natural gas production" means domestic natural gas produced from a qualified marginal well. Section 45I(c)(3)(A) provides that a qualified marginal well is a domestic well (i) the production from which during the taxable year is treated as marginal production under § 613A(c)(6)(D), or (ii) which during the taxable year (I) has average production of not more than 25 barrel-of-oil equivalents per day, and (II) produces water at a rate of not less than 95 percent of total well effluent.
- (3) Section 613A(c)(6)(D) provides that "marginal production" means domestic natural gas produced during any taxable year from a property that is a stripper well property for the calendar year in which the taxable year begins or a property of which substantially all of the production during the calendar year is heavy oil. Under IRC § 613A(c)(6)(E), a "stripper well property" is, with respect

to any calendar year, any property producing not more than 15 barrel equivalents per day, determined by dividing the average daily production of domestic crude oil and domestic natural gas from producing wells on the property for such calendar year by the number of such wells on the property. Heavy oil is defined in IRC § 613A(c)(6)(F) as domestic crude produced from any property if such crude oil had a weighted average gravity of 20 degrees API or less (corrected to 60 degrees Fahrenheit).

- (4) Note: In IRC § 613A(c)(8)(D)(iv) and the underlying regulations one barrel of crude oil is equivalent to 6 MCF of natural gas.
- (5) IRC § 45I(c)(2)(A) provides that generally only the first 1,095 barrels or barrel-of-oil-equivalents (as defined in IRC § 45K(d)(5)) produced during the taxable year qualify for the MWC. This limitation is proportionately reduced in the case of a short taxable year or in the case of a well that is not capable of production each day of a taxable year.
- (6) Note: In IRC § 45K(d)(5) one barrel-of-oil equivalent with respect to any fuel means that amount of such fuel which has a BTU content of 5.8 million.
- (7) The BTU content of natural gas from a well is determined by a laboratory measurement and is often stated on accounting records since natural gas is usually sold on a per-million BTU basis. A typical figure is 1,037 BTU per cubic foot (or 1.037 million BTU per MCF). [See Energy Units and Calculators Explained – British Thermal Units \(BTU\)](#) by the U.S. Energy Information Administration.
- (8) Therefore, one MCF of typical natural gas equates to 0.1788 barrel-of-oil equivalents (1.037 divided by 5.8).
- (9) Similarly, 5.593 MCF of typical natural gas equates to one barrel-of-oil equivalents. (1 divided by 0.1788).
- (10) Claiming the Marginal Well Credit of IRC § 45I
- (11) Under IRC § 45I(d)(2), the MWC is only available to taxpayer's holding an operating interest in the qualified marginal well producing the crude oil or natural gas to which the credit relates. Under IRC § 45I(d)(1) if a well is owned by more than one owner and the crude oil or natural gas production exceeds the limitation under IRC § 45I(c)(2), the qualifying production attributable to the taxpayer is determined on the basis of the ratio the taxpayer's revenue interest in the production bears to the aggregate of the revenue interests of all operating interest owners in the production. Finally, IRC § 45I(d)(3) provides that where a taxpayer's well is also eligible to claim the IRC § 45K Nonconventional Source Fuels credit for the taxable year, the MWC is unavailable unless the taxpayer elects not to claim the credit under IRC § 45K for the well.
- (12) IRC § 45I(b) provides that the credit amount can be as high as 50 cents per thousand cubic feet (MCF) of qualified natural gas multiplied by an inflation

adjustment factor. However, the credit amount is reduced by a formula that is sensitive to high domestic natural gas wellhead prices.

- (13) As stated in [Notice 2017-51](#), the credit amount used to calculate the MWC for taxable years beginning in calendar year 2016 is \$0.14 per thousand cubic feet (MCF).
- (14) As stated in [Notice 2018-52](#), the credit amount used to calculate the MWC for taxable years beginning in calendar year 2017 is \$0.51 per thousand cubic feet (MCF).
- (15) As stated in [Notice 2019-37](#), the credit amount used to calculate the MWC for taxable years beginning in calendar year 2018 is \$0 per thousand cubic feet (MCF).
- (16) As stated in [Notice 2020-34](#), the credit amount used to calculate the MWC for taxable years beginning in calendar year 2019 is \$0.08 per thousand cubic feet (MCF).
- (17) As stated in [Notice 2021-34](#), the credit amount used to calculate the MWC for taxable years beginning in calendar year 2020 is \$0.66 per thousand cubic feet (MCF).
- (18) Finally, the MWC is claimed on [Form 8904](#), Credit for Oil and Gas Production From Marginal Wells.

I. Equipment Inventory

- (1) The accounting for the individual owner-operator and the jointly owned oil and gas operating properties sometimes presents problems, especially regarding the accounting for the transfers of depreciable equipment between the lease equipment account and equipment inventory account.
- (2) The individual who owns and operates their own oil and gas leases usually makes transfers from the producing lease equipment account to the inventory account at the fair market value of the used equipment at the time of the transfer. The COPAS Bulletins specify methods of valuation to be used for such transfers. These methods generally provide for a value as a percent of new replacement cost based upon the condition of the used equipment. This value is normally used because the historical cost of the individual item of equipment is difficult to identify. If there is a large piece of equipment transferred and the original cost can be identified, it would be transferred at this identified cost. The equipment inventory account is debited with this value or cost, and the lease equipment account is credited with the same amount. The depreciation reserve account is normally not disturbed, except for the depreciation on the equipment that is transferred at cost. Generally, no depreciation is claimed on the inventory account. This inventory equipment is on standby to be placed back into active service when it is needed. This method of accounting for the equipment transfers is normally not disturbed if the taxpayer uses this method consistently, and its use does not materially distort income. If the taxpayer makes sales of

the equipment, then the gain or loss on the sale should be recognized at that time. The original cost less depreciation will be used in computing gain. Transfers from the inventory account to the lease equipment account are made at the same value. If there are purchases of equipment from outsiders and charged to the inventory account, those transfers out are usually made at cost, since the cost can be identified.

- (3) The accounting for the equipment transfers on a jointly owned lease where the joint owner-operator does not take ownership of the equipment inventory account is similar to that of the individual owner. The transfers to the inventory account from the lease equipment account are usually made at cost, if cost is identifiable, or at the fair market value of the equipment at the time of the transfer. The joint operating agreement between the joint owners and the lease operator will normally specify the method of transferring assets. See sample operating agreement in COPAS Bulletins. For a discussion of values placed on equipment by the operating agreement, see the following sections. The ownership of the inventory account is important because there has not been a disposition of the equipment if the joint owners retain ownership of the inventory account. It should be remembered that the taxpayer's method of accounting for the equipment transfers will not be disturbed if the use of the method is consistent and its use does not materially distort income.
- (4) The accounting for the equipment transfers on jointly owned leases where the operator is an outside third party presents fewer problems. Since a change in the ownership of the equipment takes place every time there is a transfer, gains and losses must be computed on each transfer. See section VI.I.1, Provisions of Operating Agreements for a full discussion of this problem and its relation to the operating agreement.

I.1. Provisions of Operating Agreement

- (1) The accounting for the equipment transfers on jointly owned leases where the joint owner-operator owns the equipment inventory account and buys and sells equipment from and to the joint owners through this account is unique. The operating agreement generally provides that equipment transferred from the lease equipment account to the inventory or warehouse account is graded according to the condition of the equipment. If COPAS guidelines are used, the grades range from "A" (for unused and not in need of repair or reconditioning) to "E" for junk (having scrap value only). The grade will dictate a specific percentage that will be multiplied by a cost to arrive at a value. For example, COPAS' website states that "B Condition material is charged at 75% of current new price. B Condition material is credited at 75% of current new price if the material was new when it was charged to the property, or at 65% if the material was used when it was charged to the property. C Condition material is always charged and credited at 50% of current market value, subject to certain provisions concerning reconditioning costs."

- (2) Thus, the grade of the equipment is either new, A, B, C, D, or junk, and carries a value equal to a percentage of new equipment cost as agreed upon in the operating agreement. Normally, Grade A equipment is valued at 90 to 100 percent of new cost, Grade B at 75 to 80 percent, etc. See [COPAS Used-Equipment Percentages](#) for guidance. The joint owners are given credit or charged on their monthly joint billings for any equipment transferred to or from the inventory account. These transfers to the inventory account constitute dispositions of property, and gains or losses on each transfer should be recognized. Transfers from the inventory account constitute purchases of equipment. The transfers to and from the inventory or warehouse account sometimes present problems. The taxpayer's method of accounting will normally not be disturbed if it accounts for gains and losses, is consistently used, and does not distort income.

I.2. Gain or Loss on Inventory

- (1) The gains and losses on the transfers of equipment should be recognized when the ownership of the property changes on the transfer. Most transfers to the inventory account are made at the price provided for in the operating agreement. This sale price is easily ascertained since it can be found on the monthly joint billings. The taxpayer's cost basis in the equipment transferred from the oil and gas leases, however, is sometimes impossible to ascertain. Thus, when the tax cost cannot be determined, the lease equipment account is usually credited with the full sales price amount. This method of accounting will normally not be disturbed as long as the lease equipment account balance exceeds the depreciation reserve balance. On those transfers where the cost can be ascertained, the lease equipment and reserve accounts are charged with the cost and depreciation figures, and the gain or loss is recognized. If the amounts are material and the tax cost can be ascertained, the agent should make sure that the gain or loss on the transfers is recognized.

VII. Oil and Gas Well Depletion

A. Introduction

- (1) An oil and/or gas producing property is a "wasting" asset: the quantity of oil and/or gas found in any natural deposit is finite. As the oil and/or gas is produced and removed from the deposit, the deposit is lessened or depleted. The owner of an economic interest in an oil and/or gas producing property may be entitled to a deduction from income for depletion of such economic interest as the oil and/or gas is produced and sold. Mineral interests, royalties, working interests, overriding royalties, net profits interests, and production payments are all economic interests in mineral deposits.]
- (2) Once a mineral property becomes productive, the owner or owners of economic interests in that property must recover their cost basis either through the depletion deduction under IRC § 611(a), (or, in the event of a sale or other

disposition prior to the total depletion of the property, as otherwise provided in the Code for such sale or other disposition.

- (3) Section 611(a) provides, in the case of oil and gas wells, for a reasonable allowance for depletion as an allowable deduction in computing taxable income.
- (4) The Code provides two specific methods of computing the depletion deduction:
 - Cost depletion under IRC § 612, and
 - Percentage depletion under IRC § 613.
- (5) The cost depletion method is essentially a “unit of production” method of computing the allowable current tax period deduction which is based on the number of units to be produced from the asset. This computation is made using the taxpayer’s basis as provided in IRC § 612.
- (6) The percentage depletion deduction is a specified percentage of the taxpayer’s gross income from the property but is limited to 100 percent of the taxpayer’s net taxable income from the property. This limitation is computed without allowance for depletion under IRC § 611(a) or the deduction under IRC § 199A. Refer to section VII.B.4, Net Taxable Income from the Property for a full discussion of this limitation.
- (7) Section 613A severely restricts the availability of percentage depletion for oil and gas production. Under IRC § 613A(c), taxpayers classified as Independent Producers or Royalty Owners may claim percentage depletion on a limited volume of oil and gas production each year.
- (8) If the percentage depletion is computed pursuant to IRC § 613A(c), there is also a further limitation of 65 percent of the taxpayer’s taxable income from all sources for the tax period in IRC § 613A(d)(1). The method of computing the depletion deduction is not elective. The taxpayer must be allowed to use the computation which allows the largest deduction. Allowable depletion, which is the higher of cost or percentage depletion, reduces the taxpayer’s depletable basis (but not below zero) in the property. See Treas. Reg. § 1.611-1(a).
- (9) As this can involve a highly complex computation, an agent encountering a depletion problem should consult an engineer for assistance.
- (10) The depletion computation is “off” book and the calculation of percentage depletion is solely for tax purposes. Corporate taxpayers should make a Schedule M-1 adjustment for excess percentage depletion over cost.

B. Purpose and Statutory Authority for Depletion

- (1) The purpose of the cost depletion computation and deduction is to allow the taxpayer a tax-free return on capital investment. The purpose of the percentage depletion deduction is to avoid the problems which were connected with the “discovery value” depletion deduction and provide incentives to investors and operators to undertake the very risky drilling and exploration operations

necessary to find and produce oil and gas. “Discovery value” depletion will not be allowed.

- (2) Cost depletion deductions are authorized by IRC §§ 611 and 612, and the regulations issued pursuant to these sections. Prior to January 1, 1975, percentage depletion was authorized by IRC § 613 and the regulations issued pursuant to this section. For oil and gas production on and after January 1, 1975, however, the depletion deduction is calculated without regard to percentage depletion authorized by IRC § 613, except in certain circumstances under IRC § 613A and the regulations thereunder. Those limitations are discussed in section VII.D, Percentage Depletion.

B.1. Economic Interest

- (1) The depletion deduction under IRC § 611 is only available to owners of an economic interest in an oil and gas property. An economic interest in such property is possessed where a taxpayer has (1) acquired by investment any interest in minerals in place and secures, by any form of legal relationship, and (2) the taxpayer looks to the income derived from the extraction of the oil and/or gas for a return on his investment. See *Commissioner v. Southwest Exploration Co.*, 350 U.S. 308 (1956); Treas. Reg. § 1.611-1(b). Although a production payment is by definition an economic interest, IRC § 636 provides that the payee will not be treated as the owner of an economic interest.
- (2) In many foreign countries, a corporation cannot acquire legal title to an oil and gas property, or to any petroleum or other hydrocarbons contained therein or produced therefrom. Instead, the corporation must, at its own risk, advance all funds necessary for the exploration, development, and production of the oil and gas on the property and sell all resulting production to the foreign country at the competitive world market price. In such case, the Service has held in Rev. Rul. 73-470, 1973-2 CB 88, that the corporation is deemed to have an economic interest in the property even though it lacks legal title. See also *Tidewater Oil Co. v. United States*, 339 F.2d 633 (Ct. Cl. 1964); *Southwest Exploration Co.*, 350 U.S. 308.
- (3) The agent must distinguish between an economic interest, which allows the taxpayer to claim the depletion deduction, and an economic advantage, which does not. The contractual right to purchase oil or gas after it has been produced is an economic advantage. See Rev. Rul. 68-330, 1968-1 CB 291. Numerous courts have defined “economic interest” using the two-part definition above. See *Tidewater Oil Co.*, 339 F.2d 633; 14 AFTR 2d 6043; 65-1 USTC Para. 901A; *CBN Corp. v. United States*, 364 F.2d 393 (Ct. Cl. 1966), 18 AFTR 2d 5143; 66-2 USTC 86,703; cert. denied, 386 U.S. 981; *Southwest Exploration Co., v. Commissioner*, 350 U.S. 380 (1956); 48 AFTR 683; 56-1 U.S. 54,691; and *Estate of Donnell v. Commissioner*, 48 T.C. 552 (1967), aff’d in part, rev’d in part, 417 F.2d 106 (5th Cir. 1969).
- (4) The agent should be able to determine the “economic interest” status of an asset by obtaining from the taxpayer’s property acquisition files, or any other

source, the documents, letter agreements, assignments, unitization agreements, and operating agreements related to the mineral property. The division order is the legal abstract of mineral interest in a specific property and indicates each party's percentage of ownership. These documents should be studied carefully for the nature of the interest owned by the taxpayer.

- (5) The agent should not be concerned about the economic interest status unless the taxpayer has claimed depletion deductions or IDC deductions. These are the only types of deductions which are affected.
- (6) If the taxpayer claims cost depletion deductions, the agent should be primarily concerned with basis, reserves of oil and/or gas, current tax period production, and the computation of the deduction.

B.2. Definition of Depletable Income

- (1) For tax years ending prior to January 1, 1975, the gross income from the property is the amount for which the taxpayer sold the oil or gas in the immediate vicinity of the well. However, IRC § 613A severely limited both the use of percentage depletion under IRC § 613 to certain taxpayers and the maximum deduction allowed for these taxpayers using percentage depletion.
- (2) Thus, in some instances, the entire gross income from the property may not be subject to percentage depletion because of the limitations of IRC § 613A.
- (3) In computing percentage depletion, the gross income from the property must meet the provisions of IRC § 613A(b), and IRC § 613A(c). Refer to section VII.D, Percentage Depletion for full details.

B.3. Gross Income from the Property

- (1) For oil and gas wells, the Code does not define gross income from the property. However, Treas. Reg. § 1.613-3(a) still provides, "In the case of oil and gas wells, gross income from the property, as used in IRC § 613(c)(1), means the amount for which the taxpayer sells the oil or gas in the immediate vicinity of the well. If the oil or gas is not sold on the premises but is manufactured or converted into a refined product prior to sale, or is transported from the premises prior to sale, the gross income from the property shall be assumed to be equivalent to the representative market or field price of the oil or gas before conversion or transportation." For court determinations of representative market or field price, see the following:

Shamrock Oil & Gas Corp. v. Commissioner, 35 T.C. 979 (1961), acq. 1966-2 C.B. 7, amended by T.C. Memo. 1963-35, aff'd, 346 F.2d 377 (5th Cir. 1965), cert. denied, 382 U.S. 892 (1965);

Hugoton Production Co. v. United States, 315 F.2d 868 (Ct. Cl. 1963); 11 AFTR 2d 1198; 63-1 USTC 88,025;

Panhandle Eastern Pipe Line Co. v. United States, 408 F.2d 690 (Ct. Cl. 1969); 23 AFTR 2d 69-933; 69-1 USTC 84,214;

Exxon Corp. v. United States, 88 F.3d 968 (Fed Cir. 1996); 96-2 USTC 50,324; 77 AFTR 2d 2521; , cert. denied, 520 U.S. 1119 (1997);

Exxon Corp. v. Commissioner, 102 T.C. 721 (1994); and

Exxon Mobil Corporation v. United States, CA-FC, 2001-1 USTC 50,348, aff'g in part, rev'g in part, 2000-1 USTC 50,116, 45 FedCl 581, 244 F.3d 1341 (Fed. Cir. 2001),

- (2) Of prime importance in determining gross income from the property is the principle that only 100 percent of the proceeds of actual sales of oil and gas production in the immediate vicinity of the well or representative market or field price are subject to depletion.
- (3) The deduction for depletion is to be equitably apportioned between the lessor and lessee. See Treas. Reg. § 1.611-1(c)(2). The U.S. Supreme Court held in *Helvering v. Twin Bell Oil Syndicate*, 293 U.S. 312 (1934); XIV-1 C.B. 253; 14 AFTR 712; 35-1 USTC 386) that this meant the gross income on which percentage depletion is computed.
- (4) When oil or gas is sold in the immediate vicinity of the well to an unrelated purchaser, there are relatively few problems. Gross income from the property includes any production or severance taxes which are the liability of the seller. These taxes are usually withheld by the purchaser (pipeline company) and paid to the state. If the purchaser of the oil or gas charges the seller a fee for gathering, transporting, and/or compressing the oil or gas, or if the seller performs these services, these costs are a decrease in gross income from the property and not lease operating expenses. Refer to Rev. Rul. 75-6, 1975-1 CB 178, for compression cost treatment and *Panhandle Eastern Pipe Line Co. v. United States*, 408 F.2d. 690 (Ct. Cl. 1969); 23 AFTR 2d 69-933; 69-1 USTC 84, 214) for transportation cost treatment. The agent should analyze lease operating expenses and "other" expenses to determine if these types of costs have been properly treated when paid to the pipeline purchaser. Analysis of depreciation accounts will indicate if pipelines or compressors are in use by the taxpayer. Gross income from the property can be verified as to the source and type of income by studying and tabulating pipeline run statements and division orders. The contract between the purchaser and producer for the sale of the oil or gas may have provisions which clearly indicate the portions of the purchase price which exceeds the field price of oil or gas in the immediate vicinity of the well.
- (5) The working interest owner's gross income from the property must not include income from production which is paid to royalty owners and the other owners of economic interests in the property. See *Mesa Petroleum Co. v. Commissioner*, 58 T.C. 374 (1972); Treas. Reg. § 1.613-2(c)(5)(i).
- (6) When produced gas is not sold in the immediate vicinity of the well but is transported by the producer to a gasoline plant and processed for the extraction of liquid hydrocarbons, gross income from the property is deemed to be equivalent to the representative market or field price. However, there are

instances in which there is no determinable representative market or field price. These situations have given rise to several court cases:

Weinert's Estate v. Commissioner, 294 F.2d 750 (5th Cir. 1961); 8 AFTR 2d 5417; 61-2 USTC 81,606;

Mountain Fuel Supply Co. v. United States, 449 F.2d 816 (10th Cir. 1971); 28 AFTR 2d 71-5833; 71-2 USTC 87,650; cert. denied, 405 U.S. 989

Shamrock Oil & Gas Corp. v. Commissioner, 35 T.C. 979 (1961), acq. 1966-2 C.B. 7, amended by T.C. Memo. 1963-35, aff'd, 346 F.2d 377 (5th Cir. 1965), cert. denied, 382 U.S. 892 (1965)

- (7) In the above instances, it is necessary to make a determination of gross income from the property by studying the data. If the depletion claimed for gas production is significant, the agent should request the assistance of an engineer.
- (8) The percentage depletion deduction is based on a percent of the gross income from the property, which means the amount for which the taxpayer sells the oil or gas in the immediate vicinity of the well. See Treas. Reg. § 1.613-3(a). If the sales price of the oil or gas is determined after transportation, compression, conversion, manufacturing, or similar activities, which are not production activities, the increase in the sales price attributable to those activities must be excluded from the price. See Rev. Rul. 75-6, 1975-1 CB 178.
- (9) Because the taxpayer is entitled to compute depletion on the gross income from the property, if the sales have occurred after one of the activities listed in paragraph (8) above, then a method must be devised to determine price in the immediate vicinity of the well. It should be emphasized that this is a price determination not a value determination. The proportionate profits method, which is typically applied in the case of mines to which no determinable representative market or field price exists (see Treas. Reg. § 1.613-3(d)) has not been accepted by the courts for oil and gas.
- (10) If a taxpayer has claimed percentage depletion on the sale of gas and the depreciation schedule shows the taxpayer also owns and operates a gasoline plant, the agent should analyze the source of income—plant sales or lease sales. If plant sales are allocated back to the leases, the agent should request engineering assistance.

B.4. Net Taxable Income from the Property

- (1) Percentage depletion is computed on a property-by-property basis. The agent should become familiar with the “property concept” before attempting to determine taxable income from the property. For definition of “property” for depletion purposes, see IRC § 614 and the regulations thereunder. Also, refer to section VII.D.2 – Property Defined.
- (2) Taxable income from the property is important because the percentage depletion deduction is generally limited to 100 percent of the taxable income

from the property. Refer to IRC § 613(a). Taxable income from the property is computed in accordance with Treas. Reg. § 1.613-5. For tax years beginning after December 31, 1997, and before January 1, 2008, or beginning after December 31, 2008, and before January 1, 2012, the net income limitation is suspended for domestic oil and gas production from marginal properties. See IRC § 613A(c)(6)(D).

Note: The suspension is not applicable for tax years beginning after December 31, 2007 and before January 1, 2009.

- (3) Net taxable income from the property is the gross income from the property as determined under IRC § 613(c), and further discussed in section VII.B.3, Gross Income from the Property, reduced by the following:

Operating Expenses. See IRC § 162. The agent should examine invoices on the larger accounts to confirm these expenditures are reported for the correct properties and in the correct reporting period.

Losses. See IRC § 165.

Depreciation of Lease Equipment. See IRC §§ 167 and 168. The depreciation claimed for tax deduction purposes should be deducted to reach taxable income. If depreciation is claimed for equipment which served more than one property, the deduction should be allocated among the properties on a reasonable basis.

Overhead Attributable to the Property. The taxpayer who produces oil and gas will have deductible expenses such as officers' salaries, office utilities, building depreciation or rent, and general office expenses which are not attributable to any particular property. These expenses are termed indirect or overhead expenses. Treas. Reg. § 1.613-5(a) requires that these expenses be allocated between producing activities and other activities. They must be further allocated to the individual properties on a reasonable basis. Allocation based on gross income or direct expense is acceptable, but the method used should be consistently followed. Generally, allocations of overhead among properties on the basis of direct expenses is preferred since overhead is likely to be associated with direct costs. If the taxpayer has not allocated overhead to lease operating costs, the agent should scan the depletion schedule. If no properties will be affected, or only a minimal adjustment appears likely, the agent should not pursue the overhead allocation. The agent need not make calculations to allocate to each property--only to the ones which will result in adjustment, but the agent must be able to show that the adjustment is appropriate.

Intangible Drilling Costs. See Treas. Reg. § 1.612-4. IDC should be deducted for purposes of the 100 percent limitation. See Rev. Rul. 77-136, 1977-1 CB 167. The costs of a dry-hole drilled on a lease, in an effort to penetrate and produce an already producing property, are expenses of that property. The agent may be able to determine the purpose of a well by asking the taxpayer for the AFE or its equivalent which authorized the drilling of the well. This may be in the well file or company financial records. Companies which publish

annual reports may include comments concerning some specific wells. Applications to drill the well which are filed with the state agency having jurisdiction may also indicate the purpose of the well. The IDC of wells drilled for the purpose of locating and producing another pay zone on a lease already producing are not costs of the existing property unless the taxpayer does not elect separate property treatment. Refer to section VII.D.6 - Separate Mineral Interest Election.

Taxes. See IRC § 164. Ad valorem and other taxes (other than Federal income taxes) attributable to oil and gas wells should also be allocated to the properties.

Interest. See IRC § 163. Interest expense on money borrowed to purchase or develop the property. See *St. Mary's Oil and Gas Co. v. Commissioner*, 42 B.T.A. 270 (1940).

- (4) For an example of the correct computation of "Gross Income from the Property" and "Net Taxable Income from the Property," see Rev. Rul. 79-73, CB 1979-1, 218 and Rev. Rul. 81-266, 1982-2 CB 139.
- (5) On occasion, a taxpayer may overpay IDC in a tax year and be reimbursed in the following year. The taxpayer then shows the reimbursement in the "taxable income" computation as a negative IDC deduction. This has the effect of overstating taxable income from the property. Negative IDC should be removed from the computation as its inclusion distorts the taxable income calculation. The agent should scan the IDC accounts to identify any negative entries.
- (6) If a taxpayer owns a fraction of the working interest and operates the property for others, the taxpayer charges the others an "overhead" or operating fee. This charge is income from operating properties for others and not a reduction in operating costs. When a taxpayer operates properties for others, as well as for itself, the agent should study the taxpayer's accounting for the income to verify that it is not being used to increase net income from the property or to reduce allocable overhead expenses.
- (7) Gain, under IRC § 1245, is not an allowable increase in net income from the property in the case of oil and gas wells as it is in the case of mines. See Treas. Reg. § 1.613-5(b).
- (8) A taxpayer may follow the practice of only showing the IDC of producing wells on a depletion computation schedule. Dry-hole costs or some producing well costs may be shown under "other deductions", dry-hole costs, or abandonment losses. The agent should obtain schedules and supporting documents for these accounts. A comparison of the names on various schedules may indicate a dry-hole was drilled on a producing property and its cost not deducted to reach taxable income.

Example: Taxpayer Smith's percentage depletion schedule for R. Licker Lease shows gross income of \$200,000, net income of \$80,000, with an allowable percentage depletion of \$30,000 (equal to \$200,000 multiplied by 15%). The

schedule of dry-hole costs totaling \$126,000 may include an R. Licker Well No. 7 at \$58,000. Investigation may also reveal this well was drilled as an intended extension in the known deposit. The correct percentage depletion is \$22,000 due to the 100% net income limitation. Therefore, correct net income is \$22,000 (\$80,000-\$58,000).

B.5. Produced and Sold

- (1) A depletion deduction is not allowable when the oil or gas is merely produced. The deduction is only allowable when the produced mineral product is both produced and sold, and income is reportable. See Rev. Rul. 76-533, 1976-2 CB 189; Treas. Reg. § 1.611-2(a)(2).
- (2) Oil or gas which is not sold but is transported from the property is depletable at its representative market or field price when used or consumed by the producer. See Treas. Reg. § 1.613-3; Rev. Rul. 67-303, 1967-2 CB 221; Rev. Rul. 68-665, 1968-2 CB 280.
- (3) The agent can determine the existence of depletion claimed on oil or gas which has not been sold by comparing the claimed gross income from the property for depletion computation purposes against the pipeline run statements and/or the gross income for income reporting purposes.
- (4) Gas balancing agreements can affect the reporting of gross income for taxpayers involved in a joint venture that elects out of the provisions of Subchapter K of the Code under IRC 761(a). Refer to section VI.B.3, Gas Balancing Agreements.

B.6. Representative Market or Field Price

- (1) As indicated in Treas. Reg. § 1.613-3 and section VII.B.3, Gross Income from the Property, herein, oil or gas not sold in the immediate vicinity of the well but transported, manufactured, or converted prior to sale is included in gross income from the property at the representative market or field price. The terms “representative market or field price” are not defined in the Code or Treasury Regulations but have been defined by the six court cases cited in paragraph 1 of section VII.B.3, Gross Income from the Property.
- (2) The representative market or field price is a factual determination that may vary among producer-manufacturers.
- (3) As defined by the court decisions, the representative market or field price is a weighted average price per MCF of gas in the taxpayer’s market area. The weighted average takes into account all wellhead sales of gas comparable to the gas of the producer-manufacturer in terms of quality, pressure, and location. The computation includes all wellhead sales during the tax period without regard to the date the sales agreement was contracted.
- (4) The representative market or field price may be different for two producer-manufacturers within the same field for the same year.

- (5) If, on review of the producer-manufacturer's schedules of gross income from the properties, it is found that certain amounts are periodically computed rather than entered from pipeline run statements, the agent may find that the taxpayer should be using the representative market or field price.
- (6) The agent may find under expense of operation amounts paid for compression, transportation, or other nonproducing types of expenses which indicate oil or gas is not sold in the immediate vicinity of the well.
- (7) Gas lease operating expenses are usually comparatively low. Large operating expenses for gas wells warrant close examination to discover the cause.
- (8) If an agent encounters a representative market or a field price problem, an engineer should be consulted.

C. Cost Depletion

- (1) The cost depletion deduction method assures the owner of an oil or gas producing property that the allowable tax deduction is at least equal to the investment in the depleting property and tracks as rapidly as the asset is consumed.
- (2) For computing cost depletion, a "unit cost" must first be computed by dividing the taxpayer's adjusted basis by the number of remaining recoverable units of oil and/or gas. The taxpayer's adjusted basis is determined under IRC § 1011. The number of remaining recoverable units for any tax period is the estimated number of recoverable units determined at the end of the tax period plus the number of units produced and sold during the tax period. The unit cost is then multiplied by the number of units sold during the tax period to compute the cost depletion deduction. See Treas. Reg. § 1.611-2(a).
- (3) In certain situations, cost depletion can also be based on dollar amounts. For lease bonuses and advanced royalties, see Treas. Reg. § 1.612-3(a). For example, with respect to bonuses, the taxpayer's remaining basis is first multiplied by any bonus received. This product of these amounts is then divided by the sum of the bonus and any estimated royalties the taxpayer expects to receive. The total represents the depletion on the bonus, while the remaining basis is recovered through depletion as royalties are received. See Treas. Reg. § 1.612-3(a)(1), for an example of this calculation.
- (4) If a taxpayer receives a lease bonus on wildcat acreage and claims cost depletion equal to 100 percent of cost, this has the effect of claiming the minerals are worthless as they supposedly will produce no future income. Worthlessness must be proven by an event, and where no such event has occurred no deduction is allowed. Thus, no deduction is allowed. Further, it is assumed that the lease itself has value or the lessee would not have paid the bonus. Therefore, cost depletion should not be allowed unless it is possible to make a reasonable estimate of future income and that estimated income is not zero. However, for a contrary decision, see *Collums v. United States*, 480 F. Supp. 864 AFTR 2d 80-751 (D. Wyo. 1979), with respect to which no action on

decision has been issued. See TAM 9147002 (Nov. 22, 1991). Refer to TAM 8532011 and section VII.E – Lease Bonus, for additional details on lease bonuses.

- (5) For estimates of recoverable units, see section VII.C.2, Reserves of Oil and Gas.
- (6) In large cases with numerous calculations, a taxpayer's calculations can be quickly verified through a Computer Audit Specialist.
- (7) Cost depletion, if it is greater than the allowable percentage depletion, must be allowed in lieu of, but not in addition to, percentage depletion. See Treas. Reg. § 1.611-1.
- (8) Examiners should review Exhibit 35: Cost Depletion Deductions Claimed for Oil And Gas Mineral Property.

C.1. Depletable Basis

- (1) As provided in IRC § 612, generally a taxpayer's basis for the cost depletion computation is the adjusted basis under IRC § 1011.
- (2) When a taxpayer purchases an interest in a property and there is only one asset, few cost problems arise.
- (3) Frequently, a problem of basis for cost depletion arises when a taxpayer purchases more than one asset for a lump sum. When a taxpayer purchases a producing lease and related equipment for a lump sum, the allocation of cost between leasehold (depletable) and equipment (depreciable) is controlled by Treas. Reg. § 1.611-1(d)(4), Treas. Reg. § 1.167(a)-5, and Rev. Rul. 69-539, 1969-2 CB 141. The cost is allocated between leasehold and equipment based on relative fair market values. However, Treas. Reg. § 1.1245-1(a)(5) provide that on the sale of IRC § 1245 property and non-IRC § 1245 property, if the buyer and seller are adverse as to the allocation, any arm's-length agreement between the buyer and seller will establish the allocation. In the absence of such an agreement, the allocation is made by considering the appropriate facts and circumstances.
- (4) The allocation of the purchase price may involve a potential whipsaw (aka correlative adjustments) situation. Refer to [IRM 4.10.7.4.9 \(01-01-2006\)](#). When a material amount of tax is involved, secure the returns of both sides to the transaction to ensure consistency in the treatment of the transaction.
- (5) Allocation of a lump-sum purchase price between leasehold and equipment is usually an engineering problem. The agent should secure the following before requesting engineering services:
 - copies of the contracts and purchase agreements
 - taxpayer's allocation method
- (6) Allowable depletion deductions reduce the taxpayer's remaining basis for cost depletion computations. Accounts should be maintained so that all capitalized

cost and all allowable depletion is accumulated. If costs exceed the depletion reserve (accumulated depletion), the difference is the “remaining basis.” The effect of this is that an addition to capital of any asset may be fully offset by previously allowed percentage depletion so that, immediately after a substantial capitalization, the taxpayer’s “remaining basis” may be zero. See Rev. Rul. 75-451, 1975-2 CB 330; Treas. Reg. § 1.614-6(a)(3), Example 1.

(7) Costs which should be capitalized include:

purchase price or bonus,

attorney fees,

abstract fees,

commissions or other fees paid in connection with acquisition of the property,

IDC, and

equipment costs paid in excess of the percentage applicable to the interest owned by the taxpayer. See Treas. Reg. § 1.612-4(a)(3).

(8) Other costs that may affect basis are:

IDC which the taxpayer has not elected to expense under IRC § 263(c),

delay rentals,

equipment costs which are required to be capitalized under Rev. Rul. 69-332, 1969-1 CB 87, and

favorable geological and geophysical costs for properties outside the U.S. See Rev. Rul. 77-188, 1977-1 CB 76; Rev. Rul. 83-105, 1983-2 CB 51; Section II.C.5 – Geological and Geophysical Expenditures.

C.2. Reserves of Oil and Gas

(1) “Reserves” of oil and gas as of any date means the number of units currently expected to be recovered subsequent to that date.

(2) In the computation of cost depletion, the “unit” to be used is the principal unit(s) paid for in the products sold. See Treas. Reg. § 1.611-2(c)(1). The unit for oil is barrels and for natural gas it is thousands of cubic feet (MCF). The Service has traditionally allowed taxpayers to use the unit of the predominate product produced from each property or the “barrels of oil equivalent” which can be obtained by converting MCFs of gas to equivalent barrels by using by a conversion factor of approximately 6 MCF per barrel.

(3) The estimates of reserves of oil or gas must be made “according to the method current in the industry and in light of the most accurate and reliable information obtainable.” See Treas. Reg. § 1.611-2(c)(1). The estimate (quantity) includes “developed” or “assured” and “probable and prospective” deposits. Industry definitions of proved reserves (proved developed and proved undeveloped) refer to minerals that are reasonably known, or on good evidence believed to

exist when the estimates are made according to the method current in the industry and in the light of the most accurate and reliable information obtainable. All proved categories correspond to reserves described in Treas. Reg § 1.611-2(c)(1) and should be included in the recoverable units for computation of cost depletion deduction. The examiner should closely review the taxpayer's reserves estimation in light of operations or development work prior to the close of the taxable year, and include additional reserves required by applicable regulation to be consistent with industry standards and supported by taxpayer's actual practices.

- (4) Effective for tax years ending on or after March 8, 2004, taxpayers may elect to use a "safe harbor" to calculate their total recoverable units. See Rev. Proc. 2004-19, 2004-1 CB 563. Under this Revenue Procedure, total recoverable units are generally set equal to 105 percent of property's "proved reserves" (both developed and undeveloped) as defined by the 17 C.F.R. § 210.4-10(a) of Regulation S-X. The safe harbor must be used for all domestic oil and gas properties owned by the taxpayer. See Exhibit 31: Rev. Proc. 2004-19 and The Elective Safe Harbor For Determining a Property's Recoverable Reserves For Purposes Of Computing Cost Depletion for guidance on how to apply the safe harbor provided by Rev. Proc. 2004-19.
- (5) Computations for any tax period are the "reserves" at the end of that tax period plus the units produced during that tax period. See Treas. Reg. § 1.611-2(a)(3). This determination is important because the formula to compute cost depletion is generally the same as the one used to compute "depreciation, depletion, and amortization" (DD&A) for financial accounting. However, the amounts inserted into the various portions of the calculation are different. Care should be taken to assure that adjusting entries are being made to book amounts before tax cost depletion is calculated.

$$CD = CP \times [ATB / (CP + FP)]$$

Where:

ATB = Amount of depletable tax basis remaining

CD = Cost Depletion

CP = Current Production

FP = Future Production as of end of year

- (6) IRC § 611(a) provides for situations in which a revision of estimates impacts the calculation of depletion allowance. For purposes of cost depletion, the taxpayer is not permitted to revise the reserve estimate based solely on economic factors, without operations or development work indicating the physical existence of a materially different quantity of reserves than originally estimated to purchase or to develop the property. See *Martin Marietta Corp. v. United States*, 7 Cl. Ct. 586 (Cl. Ct. 1985).

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

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

- (8) Making estimates of the reserves of oil or gas is an engineering project. In most cases when cost depletion deductions are significant, the taxpayer will have "in-house" engineers or outside consultants prepare the estimates of reserves for use by the accounting department. These estimates may be used for full cost accounting financial statements and/or tax computations. It is important to understand that the circumstances under which a reserves estimate may be changed for tax purposes are different from circumstances under which reserves can be changed for financial reporting purposes. The agent should obtain copies of these estimates and forward them to the engineer. Engineers should refer to Section VII.C.3, Appropriate Additional Reserves of Oil and Gas.
- (9) If a taxpayer's cost depletion approaches or exceeds 50 percent of the net taxable income from the property or the cost per barrel of oil produced appears excessive, the agent should investigate the facts concerning the acquisition of the property and the basis in the property. There may be errors in the allocation of cost, estimation of reserves, or basis claimed. Units claimed to be produced for depletion purposes may exceed those reported for income reporting purposes. Sometimes assets transferred between subsidiaries may have been transferred at "book" rather than tax basis. Assets transferred between subsidiaries may have been transferred at tax cost, but the related reserve accounts may not have been transferred. IDC which were expensed for tax purposes may have been capitalized for "book" and cost depletion purposes. In years that percentage depletion exceeded cost depletion the excess percentage depletion may not have been deducted from cost basis.

C.3. Appropriate Additional Reserves of Oil and Gas

- (1) Disputes with taxpayers often arise in determining the quantity of "probable" or "prospective" reserves to be included in a property's total recoverable units from oil and gas wells for purposes of computing cost depletion under IRC § 611.
- (2) Under Treas. Reg. § 1.611-2(c), if it is necessary to estimate or determine with respect to any mineral deposit as of any specific date the total recoverable units of mineral products reasonably known, or on good evidence believed, to have existed in place as of that date, the estimate or determination must be made according to the method current in the industry and in the light of the most accurate and reliable information obtainable. The estimate of the recoverable

units of the mineral products in the deposit for the purposes of valuation and depletion should include as to both quantity and grade:

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

Probable or prospective ores or minerals (in the corresponding sense), that is, ores or minerals that are believed to exist on the basis of good evidence although not actually known to occur on the basis of existing development. Such probable or prospective ores or minerals may be estimated: (1) as to quantity, only in case they are extensions of known deposits or are new bodies or masses whose existence is indicated by geological surveys or other evidence to a high degree of probability, and (2) as to grade, only in accordance with the best indications available as to richness.

- (3) The minerals primarily produced in the petroleum industry are liquid and gaseous hydrocarbons. These are commonly referred to as oil, gas, and natural gas liquids. Some byproducts such as carbon dioxide and sulfur are also produced. Recoverable units or reserve volumes for hydrocarbons are usually reported as barrels (BBL) for liquids and thousands of cubic feet (MCF) for gases by domestic companies. Reserves may also be recorded in terms of barrel of oil equivalents (BOE) where the gas has been converted to an equivalent liquid volume (based on BTU content) and added to the oil reserves. International companies may use other units of measurement for reserves in foreign locations. Examiners/engineers need to be aware that there are variations in reserve volume nomenclature, that standard conditions of volume measurement vary somewhat, and that conversion of gas volume to oil volume may be a source of error in determining hydrocarbon reserves.
- (4) IRS examiners/engineers should ensure that the taxpayer included all proved reserves (both developed and undeveloped) and appropriate probable reserves in the cost depletion calculation. See paragraph 14 of section VII.C.4, Problems in Determining Recoverable Reserves.
- (5) To minimize disputes over probable reserves, the Service promulgated a safe harbor that taxpayers can elect for tax years ending on or after March 8, 2004. Refer to Rev. Proc. 2004-19, 2004-1 CB 563 and paragraph 4 of section VII.C.2 – Reserves of Oil and Gas.

C.4. Problems in Determining Recoverable Reserves

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

Reserves, recoverable units, expected ultimate recovery;

Probable, prospective, possible, potential;

Non-producing, undeveloped, noncommercial, static; and
Likelihood, reasonable certainty, confidence, probability.

- (2) Taxpayers estimate, compile, utilize, and report reserves in different ways for different purposes. Taxpayers may have reserve estimates for internal purposes different from those reported to the IRS. Taxpayers may consider “static reserves” to be reserves that are proved in the technical sense, but not commercially recoverable due to economic or political reasons.
- (3) For the same occurrence (or anticipated occurrence) of oil and gas, taxpayers may determine different quantities associated with different categories. For example, the quantity of “unrisked” probable reserves may be higher than the “most likely” probable reserves.
- (4) Taxpayers may estimate proved reserves down to the property level, but unproved reserves only down to the field level. Taxpayers may also have estimates of unproved reserves that are not in a ledger format, but instead are contained in analyses of specific property acquisitions.
- (5) Examiners are likely to find that no “appropriate additional reserves” have been incorporated by the taxpayer in its cost depletion computation.
- (6) Publicly traded oil companies must annually submit an estimate of their proved reserves (both developed and undeveloped) to the Securities and Exchange Commission (SEC) (such reports are available online at the SEC’s [Electronic Data Gathering, Analysis, and Retrieval](#) (EDGAR) system). Many taxpayers use these same reserves for cost depletion. However, some taxpayers exclude subcategories such as proved undeveloped reserves or proved non-producing reserves. SEC reserves can be very susceptible to negative changes in economic conditions and may be less than the true proved reserves for particular properties. The SEC’s reserves definitions and reporting guidelines for oil and gas activities are contained [in 17 C.F.R. § 210.4-10 of Regulation S-X of the Securities Exchange Act of 1934](#).
- (7) The SEC’s definitions of reserves and reporting guidelines were essentially unchanged from 1978 to 2009. A major effort to modernize those items occurred in the late 2000s, and, as a result, submissions to the SEC after December 31, 2009, must comport with the revised SEC regulation. The older definition of proved reserves is not available online, therefore it has been memorialized in Exhibit 29: Definitions Related to Oil and Gas Reserves in SEC Regulation S-X Prior to 2010. For convenience a portion of the current SEC reserves definitions is provided in Exhibit 30: Definitions Related to Oil and Gas Reserves in SEC Regulation S-X After 2009. The major differences are summarized as follows:

Definition of “current prices” (for determining if the reserves are economic) is now based on 12-month historical average instead of the last day of the year. Industry considered the latter to be unreliable because it was suspect to aberrations in the daily price of oil and natural gas.

Nontraditional resources (such as “oil sands” and “oil shale” that are mined) are now considered oil and gas activities.

The “certainty level” needed to classify reserves can be based on modern technologies, instead of only certain specified technologies.

For estimates of proved undeveloped reserves, the certainty criterion has been replaced by “reasonable certainty”.

Companies have the option to disclose probable and possible reserves, and definitions of those terms are provided.

- (8) The Service’s engineers have concluded that the impact of the SEC’s revisions on the cost depletion issue from a risk analysis standpoint is minor. For example, at present very few public companies have chosen to disclose probable and possible reserves. Further, even though “current prices” are now assumed equal to the prior 12-month average instead of the last day of the reporting year, some companies have announced write-downs of reserves due to declining natural gas prices in the United States.
- (9) Companies are also required by law to annually report to the Energy Information Administration (EIA) an estimate of proved reserves in the United States on [Form EIA-23L](#). Examiners should be aware of the peculiarities of this data:

Each company reports reserves for only those properties that it operates.

The reserves are reported by field, not by specific lease or property.

The reserves are reported on an 8/8ths (i.e., gross) basis; therefore, they are not net to the company’s ownership interest.

The EIA treats this information as proprietary, so examiners would have to obtain this information from the taxpayer. The EIA’s definition of proved reserves is very similar to that of the Society of Petroleum Engineers (SPE). https://www.eia.gov/survey/form/eia_23l/instructions.pdf .

- (10) The SPE is the preeminent industry organization for defining petroleum resources and reserves. For many years the SPE has worked with industry participants and other associations to promulgate both reserves definitions and other guidelines for the use of reserves preparers or reserves auditors. Its most recent efforts resulted in the publication of the Petroleum Resources Management System (PRMS) in 2007. To a large degree, the current SEC definitions generally agree with the SPE’s definitions. The SPE’s Oil and Gas Reserves Committee also issued [Guidelines for Application of the Petroleum Resources Management System](#) in November 2011. This document replaced the 2001 “Guidelines for Evaluation of Reserves and Resources” and expands the content to focus on the 2007 PRMS to classify petroleum reserves and resources. The document was updated slightly in June 2018 and is available upon request at the SPE’s [website](#).

- (11) To promote consistency of examinations, examiners and engineers should become familiar with the items mentioned above.
- (12) The SPE's definitions and classifications have been drafted in great detail. The key concepts can be seen in the following excerpts:

Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied [...]. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status.

Proved Reserves. An incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Proved Reserves are those quantities of petroleum which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. If deterministic methods are used, the term "reasonable certainty" is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate (Often referred to as 1P, also as "Proven").

Probable Reserves. An incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Probable Reserves are those additional Reserves that are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50 percent probability that the actual quantities recovered will equal or exceed the 2P estimate.

Possible Reserves. An incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Possible Reserves are those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P), which is equivalent to the high estimate scenario. When probabilistic methods are used, there should be at least a 10 percent probability that the actual quantities recovered will equal or exceed the 3P estimate.

Uncertainty in resource estimates is best communicated by reporting a range of potential results. However, if it is required to report a single representative

result, the “best estimate” is considered the most realistic assessment of recoverable quantities. It is generally considered to represent the sum of Proved and Probable estimates (2P) when using the deterministic scenario or the probabilistic assessment methods. It should be noted that under the deterministic incremental (risk-based) approach, discrete estimates are made for each category, and they should not be aggregated without due consideration of their associated risk (see “2001 Supplemental Guidelines,” Chapter 2.5.

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

(14) IRS petroleum engineers have concluded that as a factual matter:

The SPE’s definition of proved reserves refers to minerals described in Treas. Reg. § 1.611-2(c)(1) in that they are “reasonably known, or on good evidence believed to exist.” Thus, SPE proved reserves (both developed and undeveloped) should be included in the cost depletion calculation.

The SPE’s definition of probable reserves is generally consistent with minerals described in Treas. Reg. § 1.611-2(c)(1)(ii). They are reasonably analogous to “probable and prospective” ores or minerals. Thus, SPE probable reserves should be included at the appropriate time in the cost depletion calculation as discussed further in the Analysis of SPE Factual Scenarios of Probable Reserves that follows.

The SPE’s definition of possible reserves, however, is generally not consistent with minerals described in Treas. Reg. § 1.611-2(c)(1). Their low level of confidence is not consistent with minerals that are “reasonably known, or on good evidence believed to exist” or those that are “probable and prospective.” Therefore, SPE possible reserves should generally not be included in the cost depletion calculation.

C.5. Analysis of SPE Factual Scenarios of Probable Reserves

(1) The SPE’s website for reserves definitions formerly included a description of several factual scenarios for probable reserves. IRS petroleum engineers analyzed each factual scenario and determined:

Whether the described scenario meets the criteria of Treas. Reg. § 1.611-2(c)(1);

What quantity of probable reserves should be included in the cost depletion calculation; and

When the probable reserves should be included in the cost depletion calculation.

(2) Even though the SPE no longer includes these factual scenarios in its discussion of reserves, they are universal in nature and provide a good reference point for examiners/engineers. In this analysis, the terms reserves, proved reserves, and probable reserves carry the same meaning as the SPE’s

former definition of these terms. Examiners/engineers should be cognizant that any particular taxpayer's definition of these terms may differ from the SPE's. The complete analysis is contained in Exhibit 16: Analysis of SPE Factual Scenarios of Probable Reserves.

C.6. Planning and Case Management

- (1) **Case Management.** During the planning phase of the examination, the examiner/engineer should brief management regarding the taxpayer's compliance with Treas. Reg. § 1.611-2(g)(1). If prior examination histories demonstrate a pattern of the taxpayer disregarding the regulation's record keeping requirements, the examiner/engineer should seriously consider issuing an Inadequate Record Notice to the taxpayer. If records exist, but the taxpayer will not cooperate in providing information in a timely manner that will assist in the factual development of the reserves issue, the examiner/engineer should obtain appropriate approval to request assistance from Counsel in summoning the information. See IRM 25.5, Summons.
- (2) **Engineer Involvement.** Verifying reserves is within the purview of engineering specialists. Revenue agents should refer all identified cost depletion issues to a petroleum engineer. Mandatory referral criteria are described at [IRM 4.48.1.2. Referrals – Requests for Engineering and Valuation Services](#), also see [SRS Engineers Source](#). When cost depletion deductions are significant, the taxpayer will normally have "in-house" engineers or outside consultants prepare the reserve estimates for use by the taxpayer's accounting department. The taxpayer may use these estimates for full cost accounting financial statements and/or for tax. The agent should obtain copies of these estimates and forward them to the engineer with the request for engineering services.
- (3) **Computer Audit Specialist Involvement.** Taxpayer may have hundreds or thousands of properties for which it claims depletion, and the information given to the agent may not be in usable format. In that case, the agent should request a Computer Audit Specialist (CAS) convert the data on tax depletion and/or reserves schedules to a usable format. If a referral to an engineer is necessary, this should be done as early as possible. This will allow the engineer to request these files after consultation with the taxpayer and the CAS as to the best format. Otherwise, there may be delays in the examination.
- (4) **Information To Be Requested at the Outset of the Examination.** The examiner/engineer should request the following information from the taxpayer at the outset of the examination:

Detailed tax depletion ledger by tax property, which should include an explanation of the headings. The taxpayer should provide the ledger in hard copy and electronic record format, if possible;

A reconciliation of the tax return amount to the detailed tax depletion schedule. The taxpayer should provide the reconciliation in hard copy and electronic record format, if possible;

Detailed reserves and production ledger which shows all reserves, changes to reserves, and annual production by property. Taxpayers may have multiple estimates of reserves (e.g., different categories or different estimates of the same category) and all estimates should be specifically requested. It may be necessary to inquire as to what reserves estimates are maintained by the taxpayer;

A reserves handbook or reserves manual that describes how the taxpayer defines all of its different categories of reserves and what reserves the taxpayer considers recoverable;

Third-party (independent) reserves report(s) prepared for the taxpayer;

Separate property election statements; and

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

- (5) **Information To Be Requested on an “As Needed” Basis.** The examiner/engineer should request the following on specific properties as needed:

Reconciliation of annual lease production (revenue);

Reconciliation of leasehold basis and basis additions;

Structure and isopach maps;

Well logs, well data;

Unitization agreements;

Lease abandonment report;

Like-kind exchange property agreements;

Lease sale agreements;

Gas contract agreements;

Partnership agreements;

Appraisal reports performed for the purposes of sales/purchases of properties; and

Energy Information Administration (EIA) reports submitted by the taxpayer to the Department of Energy. See paragraph 9 of section VII.C.4 – Problems in Determining Recoverable Reserves, for further discussion of these reports.

- (6) For foreign properties the examiner/engineer should request:

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

for properties subject to term renewable contracts the remaining term, contract area, renewable clauses, and current efforts to renew or renegotiate contract;

copy of a current accounting manual covering depletion;
documentation which identifies property units; and
documentation which identifies changes to reserve estimates due solely to economics.

- (7) **Access to Taxpayer Personnel.** The engineer should request the identification and use of the following taxpayer personnel:

A person with knowledge of reserve accounting;

An engineer with knowledge of all of the taxpayer's reserve categories associated with specific properties; and

A liaison with personal knowledge of the computer system(s) used to compile the data for the taxpayer's cost depletion file. The computer systems include, but are not limited to, those housing the depletion schedules, recoverable reserve schedules, revenue and expense ledgers, and production data.

- (8) Treas. Reg. § 1.611-2(g)(2) provides a list of data that the taxpayer should have readily available to support its depletion deduction.

C.7. Conducting the Reserve Examination

- (1) The engineer should understand the source and descriptions of all of the information in the taxpayer's reserve and depletion ledgers.
- (2) After reconciling the tax depletion amount to the tax depletion schedules and receiving any requested information, the engineer should analyze the depletion schedules and select those properties composing the majority of the deduction for an in-depth review. Criteria to consider in selecting properties for detailed review include (but are not limited to):

Properties with high depletion rates. The depletion rate is the fraction or percentage that is multiplied by the remaining basis to arrive at the cost depletion for the year. Although there are no strict guidelines, many engineers consider a high depletion rate to be 10 percent for onshore properties, and 20 percent for offshore Gulf of Mexico properties;

Properties with material changes in reserve estimates (especially reductions);

Properties with material changes in depletion basis (especially deletions to basis);

Properties in the first few years of production; and

Properties recently farmed out/in, unitized, sold, acquired, or exchanged.

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

Comparative analyses for current and prior cycles;

Certain forms attached to the tax return, e.g., Form 4797, Sales of Business Property, and Form 8824, Like-Kind Exchanges; or

The revisions to reserves that should be available in the taxpayer's reserves ledgers. The ledgers of many taxpayers incorporate a series of "codes" to identify the nature of any revision to reserves, including those due solely to economics. An explanation of the codes should be obtained.

- (4) The engineer should determine what year-end reserves the taxpayer has included in its cost depletion calculation. The reserves might be the same as those submitted to the SEC, or they might be another figure based on company-specific guidelines. In either case the engineer should determine whether the taxpayer excluded any category of proved reserves, such as proved undeveloped or proved non-producing. The engineer should determine how the taxpayer defines, estimates, and compiles its unproved reserves. If it uses the terms "probable" or "prospective" it may not necessarily define them in a manner that is consistent with the regulations. The engineer should also compare them to the SPE petroleum reserves definitions.
- (5) The engineer should determine how the taxpayer's unproved reserves relate to its expected ultimate recovery. Unproved reserves are sometimes presented along with an associated probability of success. Engineers should determine if the quantity of unproved reserves already reflects the probability of success. The engineer may consider analyzing the unproved reserves for each of the selected properties under Treas. Reg. § 1.611-2 by referring to the SPE's Probable Reserves Factual Scenarios. See Exhibit 16: Analysis of SPE Factual Scenarios of Probable Reserves. If the engineer has any questions while conducting this analysis, they should contact the taxpayer's reservoir engineer.
- (6) After the engineer determines what quantity of unproved reserves should be included in the cost depletion calculation, the engineer should obtain and/or determine the appropriate unproved reserves on a property basis. If the taxpayer determines probable reserves only on the field level, then the engineer should allocate the reserves back to the property level on a proved reserve basis, or other reasonable method. The engineer should then recalculate the cost depletion for each of the selected properties by adding the appropriate unproved reserves to the year-end proved reserves in the denominator of the cost depletion formula.
- (7) For foreign properties, there are a variety of unique problems that can affect depletion. There may be issues involving property concepts, term contracts that may or may not have renewal clauses, production sharing agreements, economic/pricing issues, and political constraints. The engineer should consult other engineers with foreign depletion experience if necessary. A description of some of these contractual arrangements can be found in an [Appeals Settlement Guideline for the North Sea IDC Transition Rule](#). As with any issue related to a foreign entity, the engineer should consult the international examining agent.
- (8) If the engineer has further questions, Petroleum Industry Subject Matter Experts should be contacted.

C.8. Issues Related to Cost Depletion

- (1) In summary, for issues related to cost depletion, examiners should ensure the following:

Compute depletion on a property-by-property basis;

Properly allocate basis (including both depreciable and depletable) in the acquisition of multiple properties for a lump sum;

Properly match sales (usually production) and estimated reserves for each property. This information is often imported into the depletion ledger from different information systems;

Coordinate depletion deductions and abandonment losses so that no amount of basis is deducted twice;

Track cumulative depletion for each property so that depletion recapture under IRC § 1254 can be properly reported;

Conduct a close review of any deletions from depletable basis;

Make any additions to depletable basis on the original and not the remaining basis under Rev. Rul. 75-451, 1975-2 CB 330; and

Properly follow separate property elections.

D. Percentage Depletion

- (1) The percentage depletion deduction is computed as a percent of gross income from the property, limited to the net taxable income from the property. For this reason, the definition of gross income from the property is very important. See section VII.B.3 – Gross Income from the Property.
- (2) Percentage depletion is allowed under IRC § 613, but with the passage of the Tax Reduction Act of 1975 (effective January 1, 1975, and applicable to years ending after December 31, 1974), percentage depletion is restricted for oil and/or hydrocarbon gas as provided in IRC § 613A. This section is quite complex and restrictive and should be studied carefully. Retailers and certain refiners (as defined in IRC § 613A(d)) are not allowed percentage depletion on oil or hydrocarbon gas, except as provided in IRC § 613A(b).
- (3) Payments made without regard to production (lease bonuses, advanced royalties, etc.) are not subject to percentage depletion because of the enactment of IRC § 613A(d)(5). Refer to section II.B.2 - Landowner and Fee Royalty Owner.

D.1. Property Unit

- (1) The definition of “the property” is very important in the computation of the allowable percentage depletion.

- (2) The gross income from the property must include all depletable income to the property for the tax period and may not include income from any other property or source.
- (3) Expenses deducted in determining net income and 50 percent (100 percent for oil and gas properties for taxable years beginning after December 31, 1990) of net taxable income must include all expenses of the property and may not include any negative expenses or other income as offsets against expense of that property. See Treas. Reg. § 1.613-1.

D.2. Property Defined

- (1) The term “property” means each separate interest owned by the taxpayer in each mineral deposit in each separate tract or parcel of land. See IRC § 614(a).
- (2) If there is no known mineral deposit under a tract or parcel of land, for property definition it is treated as if it had one deposit.
- (3) While this definition simple, its use in practice can become complicated because of its importance and the various ways property owners, by contract, agree to divide or unitize income and/or operating expenses.
- (4) “Separate interest” refers to a type of interest. See Rev. Rul. 77-176, 1977-1 CB 77. The interest may be a working interest, royalty, overriding royalty, production payment, net profits interest, or mineral interest owned in fee.
- (5) “Each mineral deposit” refers to minerals in place. See Treas. Reg. § 1.611-1(d)(4). With respect to oil and gas wells, each separate mineral deposit refers to each separate subsurface naturally occurring accumulation of oil and/or gas which is separate and apart from and not in naturally occurring communication with any other such accumulation of oil and/or gas.

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

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

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

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

Example 5. Facts are the same as Example 4 except that an additional well has been drilled on the north side of the tract, and it also produces from the Devonian and Ellenburger zones. Also, two additional wells have been drilled

between the wells on the south side of Tract A and the well on the north side of Tract A. These wells penetrated both Devonian and Ellenburger zones and found them barren of oil. Geological studies now indicate that the wells on the south side and north side are not producing from the same structure, and the mineral deposits are not continuous across the tract. Tract A has four mineral deposits.

- (6) "Each separate tract" refers to the physical area and is delineated by legal description; i.e., part of section, section number, block or township and range, survey, county or parish, and state. All contiguous areas, even though separately described, included in a single conveyance or in separate conveyances at the same time from the same owner constitute a single tract or parcel of land. Refer to Rev. Rul. 68-566, 1968-2 CB 281, for contiguous Government leases acquired on the same bid and Examples 8 and 9 of Treas. Reg. § 1.614-1(a), for contiguous leases not originating as a single tract or parcel of land.
- (7) The criteria for tax property given previously referred to each mineral deposit. The regulations make it clear that interest in each separate mineral deposit, under a tract or parcel of land, constitutes a separate interest. Although each separate mineral interest is a separate property, such separate mineral interests under the same tract or parcel of land are considered to be "one property" unless the taxpayer elects to treat the separate properties. See Treas. Reg. § 1.614-1(a)(3).
- (8) In practice, the agent must determine the taxpayer's separate properties. Some taxpayers treat separate "wells" as separate properties. One tax property can have several wells and all the production, income, and expenses must be combined to compute depletion for that property. As stated above the computation of percentage depletion is "off book"; therefore production, income, and expenses can be reallocated by taxpayers to improper properties to maximize the percentage depletion deduction. The taxpayer's "lease files" and AFE's are a good source to determine if misallocations are present.
- (9) Horizontal drilling in shale sands has become prevalent in areas where shale deposits exist. Some taxpayers attempt to treat each well as a separate tax property. If several wells are drilled on one lease, however, the lease is generally considered to be the tax property since the underlying shale sand constitutes one mineral deposit. The election under IRC § 614(b)(2) is not available for individual horizontal shale wells since an individual well does not constitute a separate operating mineral interest. In addition, if multiple operating mineral interests are combined under a voluntary "pooling agreement", such pooling is treated as one property under IRC § 614(b)(3) if the production flows from one deposit or from more than one deposit if logical for joint development purposes and the pooled tracts or parcels of land are contiguous or in close proximity. Under Treas. Reg. § 1.614-8(b)(6) a "pooling agreement" means an agreement under which two or more persons owning operating mineral interests agree to have the interests operated on a unified basis and further agree to

share in the production on a stipulated percentage or fractional basis regardless of from which interest or interests the oil or gas is produced. A “pooling agreement” also includes a situation where one person agrees with his several royalty owners to determine the royalties payable to each on a stipulated percentage basis regardless of which lease or leases oil and gas production is from. The above rules may generally be summarized as follows:

When multiple horizontal shale wells are drilled on one lease, the lease is the tax property; and

When multiple horizontal shale wells are drilled on pooled leases, the pooling agreement is the tax property.

D.3. Separate Acquisitions of Contiguous Leases

- (1) If contiguous leases are acquired at the same time from different landowners or at different times from the same landowner, the leases constitute separate tracts and, therefore, separate properties. See Treas. Reg. § 1.614-1(a)(3).

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

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

D.4. Acquisition-Additional Working Interest

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

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

D.5. Multiple Producing Zones

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

D.6. Separate Mineral Interest Election

- (1) Notwithstanding the preceding definition of a property, if a taxpayer has two or more operating mineral interests (also known as working interest) located on a tract or parcel of land and wishes to treat them as separate properties, the taxpayer must make an election to treat them separately. See IRC § 614(b)(2). Any operating mineral interests located on a single tract or parcel of land for which no separate property treatment election has been made will be combined and treated as one property. See Treas. Reg. § 1.614-8(a)(1).
- (2) The election described in IRC § 614(b)(2) above must be made by attaching a statement to the taxpayer's return no later than the due date for the return for the later of either (1) the first taxable year beginning after December 31, 1963, or (2) the first taxable year in which any expenditure for development or operation in respect of an operating mineral interest is made by the taxpayer after its acquisition of the interest. See Treas. Reg. § 1.614-8(a)(3). The electing statement must contain all the required information listed in Treas. Reg. § 1.614-8(a)(3)(iii).

D.7. Unitizations

- (1) If one or more of a taxpayer's operating mineral interests, or a part or parts thereof, participate under a unitization or pooling agreement in a single cooperative or unit plan of operation, then for the period of such participation during taxable years beginning after December 31, 1963, such interests included in such unit shall be treated as one property, separate from the interests not included in such unit. See Treas. Reg. § 1.614-8(b)(1).
- (2) Under Treas. Reg. § 1.614-8(b)(6), the term "unitization or pooling agreement" means an agreement under which two or more persons owning operating mineral interests agree to have the interest operated on a unified basis and agree to share in production on a stipulated percentage or fractional basis regardless from which interest the oil or gas is produced. If one person owns several leases, an agreement with royalty owners to determine the royalties payable to each on a stipulated percentage basis regardless from which lease oil or gas is obtained is also a unitization or pooling agreement.
- (3) When partially or fully developed leases are unitized for further development and/or secondary recovery operations, there may be equalization payments involved. Some leases which are being unitized may be fully developed with all well sites drilled, while other leases require additional intangible drilling and equipment costs to enter the unit on an equal basis with the fully developed leases. The organizer of the unit (usually the designated unit operator) will normally prepare a schedule of the relative developed condition of each of the leases. This condition is stated in terms of dollar value of equipment and previously expended IDC. A weighted average per drill site is computed for the unit. Each lease is then assigned two values for equipment and intangible drilling costs:

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

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

- (4) If the value of a lease determined in (b) is greater than the value determined in (a), the owners of that lease will be entitled to receive the dollar value difference. If the value of a lease determined in (b) is less than the value determined in (a), the owners of that lease must pay the dollar value difference.
- (5) Payment is usually made by either one of two methods:
 - Cash payments
 - Increase the percentage of revenue to the lease owner's due payment and decrease percentage of revenue to the others until equalization has been achieved
- (6) The cash payments received are considered as "boot" in a tax-free exchange of property subject to tax. Therefore, the provisions of IRC §§ 1031, 1231, 1245, and 1254 must be considered.
- (7) Frequently, the payor of the cash payments will deduct the payments either as IDC (see IRC § 263(c)) or as operating expenses (see IRC § 162(a)). These payments are capital investments in either leasehold or equipment. See *Platt v. Commissioner*, 18 T.C. 1229 (1952), *aff'd*, 207 F.2d 697 (7th Cir. 1953). The payment for equipment does not constitute a purchase of used Section 38 property. See Rev. Rul. 82-213, 1982-2 CB 31, abrogating and superseding Rev. Rul. 74-64, 1974-1 CB 12. Therefore, the investment tax credit cannot be claimed by the purchaser.
- (8) When possible, the agent should compare the taxpayer's depletion computation schedule for the prior and subsequent years. The addition of a property with the word "unit" in its name might indicate a current unitization. The deletion of one or more properties which appeared to be making a profit, and the addition of another, might indicate a current unitization. Auditing the IDC will show the source of these costs. The agent should study the taxpayer's lease acquisition files and well files to determine each reported property's status. In scanning the depletion schedule, if the agent finds separate leases with the same royalty owner's name, check the effect of combining the computations into one to look at the tax effect. If there is an effect, check the lease and well files and/or discuss with the taxpayer to determine property status. If the agent has reason to believe a property has been unitized which may have a tax effect, a current oil and gas map should be consulted. Frequently, the map company will indicate units on the map by outlining with dashed lines.

D.8. Percentage Depletion in Case of Oil and Gas Wells

- (1) As indicated in section VII.A, Introduction to Oil and Gas Well Depletion, subsequent to 1974, no percentage depletion for oil and gas under IRC § 613 is allowable except as provided in IRC § 613A.
- (2) Section 613A states the conditions under which owners of interests in domestic hydrocarbon oil and gas wells, independent producers, and royalty owners are allowed to compute and deduct percentage depletion for oil and/or gas production under IRC § 613.

D.9. Exemption for Certain Domestic Gas Wells

- (1) Section 613A did not affect the computation of percentage depletion for two statutory categories of gas that were prevalent in the mid-1970's, but which are virtually non-existent today:
 - Natural gas sold under a fixed price contract, and
 - Regulated natural gas.

D.10. Depletion Allowable to Independent Producers and Royalty Owners

- (1) Except for the 65 percent of taxable income limitation, as provided in IRC § 613A(d)(1), a taxpayer who qualifies is allowed to compute and deduct percentage depletion under IRC § 613 with respect to a certain amount of average daily production of domestic crude oil and so much of average daily production of domestic natural gas as long as these amounts do not exceed depletable oil and gas quantities. Retailers and certain refiners, as defined in IRC §§ 613A(d)(2) and (4), do not qualify. See paragraphs (10) and (11) of this section.
- (2) For any tax year, a taxpayer's average daily oil production and average daily gas production is determined by dividing total crude oil production and total gas production by the number of days in that tax year. See Treas. Reg. § 1.613A-3 and 1.613A-7 for a further discussion of these rules and computations.
- (3) For any tax year, a taxpayer's depletable gas quantity is 6,000 cubic feet (6 MCF) multiplied by the number of barrels (BBL) of the taxpayer's depletable oil quantity which the taxpayer elects to convert to depletable gas quantity.
- (4) Effective January 1, 1990, the depletion rate for oil and gas produced by primary, secondary and/or tertiary methods or processes attributable to independent producers and royalty owners is 15 percent. See IRC § 613A(c)(1).
- (5) The tentative quantity specified in IRC § 613A(c)(3)(B) is currently 1,000 BBL.
- (6) Beginning after December 31, 1990, a 15 percent depletion rate for marginal oil or gas production properties held by independent producers or royalty owners increases by 1 percent (up to a maximum 25 percent rate) for each whole dollar that the reference price for crude oil for the preceding calendar year is less than

\$20 per barrel. Refer to IRC § 613A(c)(6) and Notice 2021-30, 2021-19 IRB 1149.

- (7) In applying IRC § 613A to fiscal-year taxpayers, each portion of such fiscal year which occurs within a single calendar year is treated as if it were a short taxable year. See Treas. Reg. § 1.613A-3(k).
- (8) For purposes of the depletable oil or gas quantity limitations, component members of a controlled group of corporations, as defined in Treas. Reg. § 1.613A-7(l), are treated as one taxpayer. The group shares the one depletable oil or gas quantity. Secondary production of a member of the group will reduce the other members' share of the group's depletable quantity. The depletable oil quantity remaining is then allocated among the entities in proportion to production of barrels of oil and gas (converted to BBL of oil at 6,000 cubic feet (6 MCF) = 1 BBL of oil). For purposes of the depletable oil or gas quantity limitation, a family group (which consists of an individual, spouse, and minor children) will be allowed only one tentative oil quantity as shown in IRC § 613A(c)(3)(B). The tentative oil quantity is allocated among the individuals in proportion to their respective production of oil and gas (converted to BBL of oil at 6,000 cubic feet (6 MCF) = 1 BBL of oil).
- (9) IRC § 613A(c) does not apply to retailers as defined in Treas. Reg. § 1.613A-7(r). See IRC § 613A(d)(2). A retailer is a taxpayer who directly, or through a related person, sells oil or natural gas or any product derived from oil or natural gas through any retail outlet or outlets and whose combined gross receipts exceed \$5,000,000 during the taxable year. Legal citations that pertain to this issue include:

Rev. Rul. 85-12, 1985-1 C.B. 181.

Rev. Rul. 92-72, 1992-2 C.B. 118.

Witco Chemical Corp. v. United States, 742 F.2d 615 (Fed. Cir. 1984). Note, however, that the preamble to the final regulations (T.D. 8348, 56 FR 21935-01) states "Treas. Reg. § 1.613A-7(r)(2) has been revised to provide that in determining whether a taxpayer satisfies the \$5 million small retailer exception of IRC § 613A(d)(2), only sales by the taxpayer to a person specified in IRC § 613A(d)(2)(B)(ii) shall be included (rather than all sales by that person). This provision is consistent with the holding in *Witco Chemical Corp. v. United States*, 742 F. 2d 615 (Fed. Cir. 1984). However, in view of the statutory language of IRC § 613A(d)(2), the regulations do not follow the holding of *Witco* with respect to the definition of a retail sale. The statute clearly indicates that the bulk sales exclusion rule extends only to bulk sales of oil and natural gas and not to products derived from oil or natural gas. (See placement of parenthetical in IRC § 613A(d)(2)). This is consistent with the legislative intent which was to exclude producers having large volume sales of crude or natural gas to industrial or commercial users from being deemed to be retailers."

Quaker State Oil Refining Corp. v. U.S., 994 F.2d 824, (Fed. Cir. 1993).

Union Texas International Corporation v. Commissioner, 110 T.C. 321 (1998).

- (10) IRC § 613A(c) does not apply to certain refiners defined in Treas. Reg. § 1.613A-7(s). See IRC § 613A(d)(4). A person is a refiner for purposes of this exemption if such person or related persons engages in the refining of crude oil and the total refinery runs of such person and related persons exceed 50,000 barrels on any one day during the taxable year. For taxable years ending after August 8, 2005, however, the per-day limitation increased to 75,000 barrels and is based on average daily refinery runs. Average daily refinery runs shall be determined by dividing the aggregate refinery runs for the taxable year by the number of days in the taxable year. A refinery run is the volume of inputs of crude oil (excluding any product derived from the oil) into the refining stream.
- (11) A taxpayer's total percentage depletion deduction under IRC § 613A(d) may not exceed 65 percent of the taxable income for the year, as adjusted. See IRC § 613A(d)(1). "As adjusted" means to eliminate the effects of:
- Any depletion on production from an oil or gas property subject to IRC § 613A(c);
 - Any deduction allowable under IRC § 199A;
 - Any net operating loss carryback to the taxable year under IRC § 172); and
 - Any capital loss carryback to the taxable year under IRC § 1212).
- (12) The percentage depletion deduction is also adjusted to eliminate the effect of any distributions to the beneficiaries of a trust. For a very limited exception in the case of a trust, see Treas. Reg. § 1.613A-4(a)(iv). See Exhibit 7: Information Required Before Maximum Allowable Depletion Can be Computed for an example. For computation of the 65 percent of taxable income limitation with respect to a corporation entitled to a deduction for dividends received under IRC § 243, see TAM 7902021.
- (13) The amount of depletion disallowed in IRC § 613A(d)(1) is carried over to succeeding years and treated as an amount allowable as a deduction. Refer to IRC § 613A(c) for each succeeding year, subject to the 65 percent limitation of IRC § 613A(d)(1). For purposes of adjustment to basis and determining whether cost depletion exceeds percentage depletion with respect to the production from a property, any amount disallowed as a deduction under IRC § 613A(d)(1) is allocated to the respective properties in proportion to the percentage depletion otherwise allowable to such properties under IRC § 613A(c). After allocation of the amounts disallowed, another comparison of cost depletion and percentage depletion will be made to allow whichever is greater. The amounts disallowed will be carried over to subsequent years. See Exhibit 8: Steps In The Computation Of Depletion For All Taxpayers Other Than Retailers Or Refiners As Defined In IRC §§ 613A(d)(2) & (4) for an example.

E. Lease Bonus

- (1) "Bonus" is the term applied to the considerations received by the lessor upon the granting or execution of an oil and gas lease or sublease. It may be paid in a lump sum or in installments.
- (2) To the payor (lessee), the bonus payment is a capital investment made for the acquisition of an economic interest in the minerals (working interest). A production payment retained by the lessor is treated as a bonus payable in installments. See Treas. Reg. § 1.636-2(a). The lessee's investment in the working interest is recoverable through deductions for depletion (if the lease becomes productive), abandonment loss (if the working interest becomes worthless or expires), or as cost of sale (if the working interest is sold).
- (3) To the payee (lessor), the bonus payment is ordinary income subject to cost depletion. See Treas. Reg. § 1.612-3(a). Percentage depletion is not allowed on lease bonus payments. See IRC § 613A(d)(5).
- (4) As explained in paragraph 4 of section VII.C, Cost Depletion, the cost depletion formula in Treas. Reg. § 1.612-3(a) does not produce a realistic result with respect to a nonproven property. However, in *Collums v United States*, 480 F.Supp. 864 (D. Wyo. 1979), the Court allowed a sublessor to use the computation to deduct 100 percent of basis in a nonproven property as cost depletion. No action of decision has been issued with respect to this case. Therefore, the case should not be followed unless it becomes apparent that the result in *Collums* will be accepted by the Service. Such is not the case at this time. See TAM 9147002; TAM 8532011.

E.1. Depletion Restoration

- (1) If an oil and gas lease on which a bonus has been paid (and depletion was claimed by the lessor) expires, terminates, or abandoned without production, the lessor must restore the depletion claimed to income in the year of such expiration, termination, or abandonment. See Treas. Reg. § 1.612-3(a)(2). However, if a taxpayer has disposed of the mineral property subsequent to the receipt of a lease bonus for granting of a lease and prior to the expiration of the lease, the taxpayer is not required to restore to income the depletion previously taken on the bonus. See Rev. Rul. 60-336, 1960-2 CB 195.
- (2) If a taxpayer reports an oil and gas lease bonus with respect to a tract of land, the agent should check prior leases on the tract. It may be that depletion taken on a prior lease, which expired in the current year, should be restored to income.
- (3) An agent may locate currently expired leases by comparing delay rental receipts from year to year on the books of the taxpayer. Any discontinued delay rentals indicate either a terminated lease and possible restoration of depletion on the bonus or a nonproducing lease that became productive.

- (4) On occasion, a lessee may wish to extend an oil and gas lease past its original termination date. This may be done by agreement to extend the lease for a stated period of time, or by the execution of a new lease to take effect immediately on expiration of the old lease. The extension of the old lease or execution of the new lease is commonly called a “top lease.” Under these conditions, the Service’s position is that the old lease has not terminated. The lessor is not required to restore the depletion taken on the old lease, and the lessee is not allowed to claim an abandonment loss of the cost in the old lease. This is true whether the old lease has been “top leased” in whole or in part. If there is a time lapse between the expiration of the old lease and the beginning of the new lease, then there is no “top lease” assuming the delay is at arm’s-length. For more information on top leases, refer to section II.C.8 - Top Leasing.

F. Partners and Beneficiaries Depletion Deduction

- (1) Oil and gas properties are frequently owned by a partnership, trust, or estate. The depletion deduction on oil and gas production is subject to special rules when mineral properties are held by a partnership, trust, or estate. The examiner must be aware of the special rules to ensure that beneficiaries and partners are not allowed to benefit by circumventing the limitations in the law.
- (2) The partnership is a favorite vehicle for conducting oil operations because of the practice and need to share the inherent risk of drilling for and producing oil and gas. Also, the partnership form is utilized widely to finance oil and gas operations that may be too costly for one individual or company. However, IRC § 703(a)(2)(F) states that the depletion deduction is not allowed at the partnership level. Instead, depletion must be computed at the individual partner’s level and is subject to the special limitations in IRC § 613A. Cost depletion and/or percentage depletion will be allowable under IRC §§ 611, 612, 613, and 613A as stated above, but only at the partner’s level. Preparers sometimes improperly deduct depletion on Form 1065, Partnership Income Tax Return, because the percentage depletion available to some or all of the partners is denied or limited under IRC § 613A. By deducting depletion on the partnership return, the net income distributed is reduced by the partnership, thereby circumventing the limitations under IRC § 613A.
- (3) Each partner must keep track of the adjusted basis in the partnership oil and gas properties for computing cost depletion and tax preference depletion. The partner’s basis on the partnership books will usually be reduced by the allocable share of depletion, although the limitations under IRC § 613A may render the partner unable to take the deduction. It is likely that the partner’s actual basis in the partnership will differ from the basis shown on Form 1065 because of the depletion deduction and other reasons. Copies of the Schedules K-1, prepared for the members of a partnership, should be inspected to ensure that the depletion deduction has not been deducted at the partnership level and allocated to certain partners to create a double deduction. In the case of limited partnerships, the partnership may borrow funds from a lending institution for the purpose of exploring or developing mineral property. Any increase in a partner’s

share of partnership liabilities is treated as a contribution of money that increases basis in the partner's partnership interest. See IRC §§ 722; 752(a).

- (4) Trusts and estates are also subject to special rules in computing depletion. The administrator or trustee should make the initial election on the Form 1041, Fiduciary Income Tax Return, as to whether cost or percentage depletion is claimed. Percentage depletion for a trust or estate is subject to the limitations in IRC § 613A.
- (5) If the administrator or trustee allocates net income to the beneficiaries, they will be considered to have received their pro-rata share of the depletion. The depletion would again be subject to the limitations of IRC § 613A(c) and (d)(1) at the beneficiaries' level. Treas. Reg. § 1.613A-3(g) explains the distribution of oil income and depletion with trusts and estates. The beneficiary is entitled to claim cost depletion, in any event, if cost exceeds the share of percentage depletion.
- (6) Examiners should carefully inspect the Form 1041 to ensure that distributions to the beneficiaries are correct and correspond to the amounts reflected on the beneficiaries' returns. It is common practice for a trust instrument to provide a reserve for depletion. In such a case, a trust or estate will frequently claim depletion on 100 percent of the oil and gas produced and the beneficiary will claim depletion on its share of the oil or gas income. This double deduction of depletion, however, should be disallowed. Refer to Treas. Reg. § 1.613A-3(g) for guidance.

G. Valuations of Oil and Gas Producing Properties

- (1) It is often necessary to determine the fair market value of oil and gas properties. Taxpayers may receive producing oil and gas properties as a result of taxable events such as corporate liquidations, exchanges of properties not qualifying for IRC § 1031 treatment, property received for services under IRC § 83, or in an outright purchase or sale. In each of these events, the consideration received is measured by the fair market value of the property.
- (2) For income tax purposes, the basis of property in the hands of a person acquiring the property from a decedent generally is the property's fair market value at date of death or "alternate date" under IRC § 2032, if elected. See IRC § 1014.
- (3) Fair market value determinations must also be made in respect to charitable contributions of property under IRC § 170(a).
- (4) The courts have considered the definition of fair market value many times. The Supreme Court in *Montrose Cemetery Co. v. Commissioner*, 105 F.2d 238, 242 (7th Cir. 1939), aff'd, 309 U.S. 622 (1940), stated, "the fair market value is a price at which a willing seller and a willing buyer will trade, both having a reasonable knowledge of the facts." Both Treas. Regs. §§ 1.170-1A(c)(2) and 20.2031-1(b) define fair market value as "the price at which the property would change hands between a willing buyer and a willing seller, neither being under

any compulsion to buy or sell and both having reasonable knowledge of the facts.” A similar definition of fair market value is found in Treas. Reg. § 1.611-1(d)(2): “Fair market value of a property is that amount which would induce a willing seller to sell and a willing buyer to purchase.”

- (5) Treas. Reg. § 1.611-2(d) provides for the priorities of methods to be used in determining the fair market value of mineral property. Under Treas. Reg. § 1.611-2(d)(2), if the fair market value must be ascertained as of a certain date, analytical appraisal methods, such as the present value method,) will not be used in the following situations:
 - If the value of a property can be determined upon the basis of cost or comparative values and replacement value of equipment; or
 - If the fair market value can reasonably be determined by any other method. *See also Green v. United States*, 460 F.2d 412 (5th Cir. 1972); 29 AFTR 2d 72-1138; 72-1 USTC 84,494.
- (6) Treas. Reg. § 1.611-2(e)(4) provides “the value of each mineral deposit is measured by the expected gross income (the number of units of mineral recoverable in marketable form multiplied by the estimated price per unit) less the estimated operating cost, reduced to a present value as of the date for which the valuation is made at the rate of interest commensurate with the risk for the operating life, and further reduced by the value of the improvements and of capital additions, if any, necessary to realize the profits.” In practice, this method requires that:
 - The appraiser project income, expense, and net income on an annual basis.
 - Each year’s net income is discounted for interest at the “going rate” to determine the present worth of the future income on an annual and total basis.
 - The total present worth of future income is then discounted further, a percentage based on market conditions, to determine the fair market value. The costs of any expected additional equipment necessary to realize the profits are included in the annual expense, and the proceeds of any expected salvaged of equipment is included in the appropriate annual income.
- (7) A valuation of an oil and/or gas property is an engineering issue and, if the tax consequences warrant, should be referred for engineering services.
- (8) The agent should obtain, if possible, the data indicated in Treas. Reg. § 1.611-2(g).

H. Natural Gas Injected for Pressure Maintenance

- (1) The physical characteristics of hydrocarbons and the reservoirs in which they are found are such that, other factors being equal, the higher the pressure in the reservoir the greater will be the ultimate recovery of hydrocarbons. This is true in the first month of production through the last month of production. Ultimate recovery is not necessarily directly proportionate to the reservoir's original pressures nor to its level during the production phase. However, for every reservoir which produces oil and gas, there is a critical pressure called the "bubble point." The bubble point, sometimes called saturation pressure, is the pressure at which gas in solution with the oil is released and "evolves" as "free gas." When the production of fluids causes the pressure in the reservoir to drop below the bubble point, the free gas begins to move through the reservoir (typically upward). The loss of solution gas "deadens" the oil the reservoir. When this happens, much more of the oil clings to the reservoir rock with consequent loss of possible oil recovery. Because of this, prudent operators use every reasonable means to maintain relatively high pressure in an oil reservoir throughout its productive life.
- (2) One method used by operators to maintain reservoir pressures at optimum levels is by the injection of natural gas. Dry natural gas can be injected in the gas cap or as "dispersed gas injection." The dry gas injected in the gas cap in the past has served a dual purpose. It provided a place of storage for gas for which there was no profitable market, and it retarded the decline in reservoir pressure. Dispersed gas injection maintains pressure in the reservoir and pushes additional oil to the producing well bores.
- (3) Another method of tertiary recovery of oil is known as "enriched gas drive" or "miscible displacement." Under this method, a "slug" of liquefied petroleum gas is injected in the reservoir. This is followed by injection of gas or water. The desired effect is that the liquefied gas is miscible with the oil, will wash it from the rocks, and push it to the producing well bores.
- (4) The tax treatment of injected gas has been addressed by the Service in multiple revenue rulings. See Rev. Rul. 68-665, 1968-2 CB 280, Rev. Rul. 70-354, 1970-2 CB 50; Rev. Rul. 73-469, 1973-2 CB 84. These rulings were issued prior to the enactment of IRC § 193 and issuance of Treas. Reg. § 193-1 which address the income tax treatment of tertiary injectant expense. Note: this is a highly technical area, and a petroleum engineer should be consulted if material losses or depreciation deductions are claimed.
- (5) Rev. Rul. 68-665, 1968-2 CB 280 holds that the value of dry gas manufactured from wet gas and used in a gasoline absorption plant is includible in determining "gross income from the property" for percentage depletion purposes. But, because the dry gas reinjected into the producing formation is not sold and contributes no value to the products sold, its value is not includible in "gross income from the property" for percentage depletion purposes.

- (6) Rev. Rul. 70-354, 1970-2 CB 50, holds that, where a taxpayer can show that a portion of the injected gas cannot be expected to be recovered with subsequent production, the costs of the unrecoverable portion are deductible under IRC § 165(a) in the year of injection (or in the subsequent year in which it can be shown that such loss has been sustained). Costs not recoverable under IRC § 165(a) are not deductible under IRC § 162 but are offset against the proceeds of the purchased gas when it is produced and sold in subsequent producing activities. Further, so-called “economic losses” are not recognized, such as when the price paid for gas purchased for injection is claimed to be higher than the price that may be realized when the gas is subsequently produced and sold. Finally, when purchased and injected gas is subsequently produced and sold, the gain (or loss) is reported as ordinary income and not subject to depletion.
- (7) Rev. Rul. 73-469, 1973-2 CB 84, modifies Rev. Rul. 70-354, 1970-2 CB 50, to the extent it holds that the costs of the unrecoverable portion of the injected gas that provides a benefit over the life of the project is deductible under IRC § 165(a) in the year of injection. Instead, such costs incurred on or after November 5, 1973, are treated as capital expenditures recoverable through depreciation. The undepreciated portion of injected gas is still deductible under IRC § 165(a) as a loss in the year it is determined the remaining gas did not benefit the production and the project was a failure.
- (8) The agent should be alert when examining lease operating expenses for evidence of expense deductions resulting from purchased gas. The actual deduction may not be listed under gas injected. It could instead be found under saltwater disposal or other similar names. Any account which totals an unusually high amount should be carefully checked against original invoices on a month-by-month basis. The agent should discuss any gas injection programs with the person knowledgeable of such production programs. The agent should also ask about the cost of injected gas and any earlier gas injection programs. It may be that gas purchased and expensed in earlier years is currently being produced, sold, and subjected to percentage depletion claimed on the proceeds. If the property is being produced under some form of unitization agreement, this agreement may contain definite provisions for differentiating between the production of previously injected gas and native gas for royalty computation purposes. If a substantial problem arises, engineering services should be requested. The engineer may have special detailed knowledge of the project.

I. Depletion for Geothermal Deposits

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

- (2) Under IRC § 613(e)(2), a geothermal deposit means a geothermal reservoir consisting of natural heat which is stored in rocks or in an aqueous liquid or vapor (whether or not under pressure).
- (3) Gross income is to be computed in the same manner as for oil and gas wells. See Rev. Rul. 85-10, 1985-1 CB 180. Technical Advice Memorandum 200308001 addressed a situation where it was impossible to determine a representative market or field price.

VIII. Sales, Exchanges, and Other Dispositions

A. Introduction

- (1) This section provides the guidelines for dealing with sales, exchanges, and other dispositions of oil and gas interests.
- (2) Frequently, oil and gas interests are transferred to other owners by assignment. The major problem that arises is the classification of the transaction as a sale, lease, or sublease. The disposition of worthless leases and abandonments will also be covered in this section since they may involve assignments.
- (3) The gain or loss resulting from these dispositions will either be taxable or deferred by nontaxable exchanges. Taxable dispositions result in either capital gains or losses or ordinary income. The disposition of an interest may trigger IDC and the depletion recapture provisions of the Code. See IRC § 1254. In such cases, there may be a problem with the classification of the transaction as a sale, lease, or sublease. Proper classification of an assignment is essential to the correct application of the tax laws.
- (4) The variety of contract assignments and interests created, transferred, and retained requires a careful reading of the legal documents as a standard examination procedure. A careful interpretation of the contract must be followed by a careful review of the accounting procedures used to record transactions. It should be remembered that the terms of a contract, rather than the intent of the parties, are generally controlling. However, the form of a transaction should not be allowed to take precedence over the real substance of a transaction.
- (5) When a lease owner transfers an oil or gas lease to another and receives cash or cash equivalent as consideration, such consideration is either a lease bonus, a sublease bonus, or proceeds from a sale. Therefore, it is important that examiners have a good knowledge of the difference between a leasing (or subleasing) transaction and a sale. If the transferor retains a nonoperating, continuing interest in the property, then the transaction is a lease or sublease and the cash (or equivalent) received is a bonus. All other such transactions are sales. Refer to section VIII.C - Sublease, for a discussion of subleases.
 - When a lease owner retains a nonoperating interest (royalty, net profits, etc.) that entitles the holder to a specified fraction of the total production from the transferred property for the entire

economic life of such property, the lease owner has retained a nonoperating, continuing interest in the property.

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

B. Sale or Lease

- (1) The transfer of oil and gas properties may constitute a lease, a sublease, or a sale. The importance of determining whether there is a sale or lease is that the character of the transaction determines the classification of the income to be reported.
- (2) If the transfer constitutes a lease, the income received by the lessor must be reported as ordinary income subject to depletion. If the transaction is a sale, the income may be treated as either ordinary income or capital gain if the property qualifies as a capital asset. See *U.S. v. Morgan*, 321 F. 2d 781 (5th Cir. 1963). The agent should be aware that, if a lease is sold and the lease is an inventory item, the proceeds from the sale will be ordinary income. All other income will be either ordinary income, capital gain, IRC § 1254, or IRC § 1231 gain, depending upon the character of the transaction, the holding period, and whether the recapture of IDC and depletion is required.
- (3) An interest in oil and gas in place is an interest in “real property” for federal income tax purposes. See Rev. Rul. 68-226, 1968-1 CB 362. This principle applies in all cases, regardless of how the oil and gas lessee’s interest is treated under state law, unless otherwise stated explicitly or by implication in a Federal statute. See *Burnet v. Harmel*, 287 U.S. 103, 110 (1932). An oil and gas lease is subject to IRC § 1231 treatment when it is sold except when such lease is merely granted or assigned.
- (4) When a landowner grants a lease reserving a royalty and receives a cash consideration, the transaction is considered a lease arrangement subject to ordinary income and not a sale. See Rev. Rul. 69-352, 1969-1 CB 34.
- (5) In *Exxon Mobil Corp. v. United States*, the Fifth Circuit considered whether the exploration and development agreements Exxon Mobil Corporation (Exxon) entered into with Qatar and Malaysia, separately, were mineral sales or minerals leases. 43 F.4th 424 (5th Cir. 2022). The terms of each agreement were substantially similar granting Exxon a right to explore and extract minerals within each country's territory in exchange for payments that were determined by reference to the amount of minerals extracted or products produced. *Id.* at 427. Under each agreement, Exxon was also required to build and operate facilities and other infrastructure for production that would revert to each government when the agreements ended. *Id.* In determining whether the agreements were mineral leases or mineral sales, the Court focused its analysis on whether the foreign governments retained an economic interest in

the mineral deposits that Exxon was extracting. *Id.* at 428-29. An agreement is classified as a lease when an economic interest is retained. *Id.* To have an economic interest in minerals in place, a person must have an investment in the minerals and a right to income that is dependent solely on mineral extraction. *Id.* at 429 (citing Treas. Reg. 1.611-1(b)); see also Section VII.B.1. Economic Interests for a detailed discussion and definition of economic interest. The Court held the agreements Exxon entered into with each foreign government were leases because each government retained an economic interest where payment was dependent on the amount of minerals extracted or products produced regardless of any additional terms in the agreement that would not qualify as an economic interest. *Id.* at 430-34. Examiners should review the case for a detailed discussion of the distinction between a sale and lease of an oil and gas property.

- (6) Once the transaction has been determined to be a sale, the agent must determine whether the property is producing or nonproducing. The sale of nonproducing property will usually result in capital gain treatment. The sale of producing property may result in a combination of ordinary income, capital gain, and IRC § 1231 gain. As previously stated, mineral leases (developed or undeveloped) are usually real property used in a trade or business. Related lease buildings, equipment, and expenses deducted for tertiary injectants are subject to the recapture provisions of IRC §§ 1245 and 1250. Section 1254 may require the recapture of IDC and depletion as ordinary income. Therefore, except for the recapture provisions, the gain from the sale or exchange of an oil and gas property is treated as capital gain in accordance with IRC § 1231. Losses are treated usually as ordinary losses under IRC § 1231.
- (7) A sale of an interest in oil and gas properties may involve the whole property interest or only a part. Examples of fractional sales are as follows:
 - An owner may assign an entire interest or a fractional interest. For example, the owner of the working interest in a tract of land might assign a fractional share of the working interest to another party. Alternatively, the owner might assign the entire working interest in (say) the western one-half of the tract to another party.
 - The owner of a working interest may “carve out” (from its working interest) any type of continuing nonoperating interest in the property and then assign that interest to another party. For example, the owner of a working interest might carve out a 1/16th overriding royalty interest and sell that interest to another party.
 - An owner of a continuing property interest may assign that interest and retain a non-continuing interest in production of the property. For example, the owner of a working interest in a producing property with ten years of future production might

assign the entire working interest in the property but retain a production payment defined as a 1/4th overriding royalty interest that extinguishes after passage of five years.

- (8) Most leases are transferred by either sale, sublease, or assignment. However, occasionally there may be a nontaxable exchange. Exchanges of property of like kind held for investment, or for use in a trade or business, may be nontaxable under IRC § 1031(a). If boot or other consideration is received on the exchange of such properties, however, the gain is taxable to the extent of the boot received. Refer to IRC §§ 1031(a), (b), and (c), and the regulations thereunder.
- **Note:** Beginning after December 31, 2017, IRC § 1031 like-kind exchange treatment generally applies only to exchanges of real property held for use in a trade or business or for investment, other than real property held for sale. An exception applies to certain exchanges of personal and intangible property started in 2017 and completed in 2018. An interest in oil and gas in place remains an interest in "real property" for federal income tax purposes. See Rev. Rul. 68-226, 1968-1 CB 362 and Treas. Reg. §§ 1031(a)-3(a)(1) and 1031(a)-3(a)(3).
- (9) When a sale of an entire interest in a lease is for cash, the characterization of gain or loss from the sale is simple, as previously discussed in paragraph (2). However, when a fractional interest is sold for cash, or for consideration other than cash, a problem may develop in allocating the cash or fair market value of the other consideration between the leasehold and equipment. Since these allocations must be made based on fair market values, they should be made by a petroleum engineer.
- (10) If a taxpayer assigns a working interest together with the related lease equipment to another and receives no cash consideration but retains a nonoperating interest (overriding royalty or net profits interest), no deductible loss is allowable. The remaining basis in the leasehold and equipment becomes the basis in the interest retained. See Rev. Rul. 70-594, 1970-2 CB 301; GCM 23623, 1943 CB 313.
- (11) The examination techniques used in determining whether a transfer of an oil and gas lease has occurred are the same as in any other industry. One procedure is to look at the balance sheet to determine if leases have been transferred, sold, or abandoned. Once you have determined that a transfer has occurred, look at Schedule D to see if any capital gains have been reported. If the sale cannot be verified, it may be appropriate to ask for a list of the oil and gas properties that have been transferred.
- (12) The main examination problem with a lease transfer is determining whether the transfer is a sale or a lease. Obtain a copy of the sale agreement and determine whether the transaction should be classified as a sale, lease, or sublease. Once

the transaction is properly classified, the agent can easily apply the correct tax treatment to the transaction.

B.1. Sale of Leasehold After Development

- (1) When a lease is sold or exchanged, a gain or loss is realized based on the difference between the selling price and the adjusted basis of the property sold.
- (2) The adjusted basis of the leasehold is determined by taking the original cost of the property, increasing it for capital additions, and reducing it by depletion allowed or allowable. Any write-offs for abandonments, transfers, partial sales, etc., will also decrease the adjusted basis.
- (3) Additions to the basis should include costs such as bonuses paid for the lease, attorney fees, and other expenses incurred in connection with the acquisition.
- (4) Regarding taxpayers that dispose of properties while amortizing related G&G expenditures under IRC § 167(h), see LAFAs 20163501F where a taxpayer could not include unamortized G&G amounts in the basis of an oil and gas property for purposes of computing gain or loss. Nor could the taxpayer immediately deduct the remaining amortizable G&G expenses that it paid or incurred in connection with the exploration and development of the properties. Instead, the taxpayer was required to deduct the remaining G&G in accordance with the original IRC § 167(h) amortization schedule.
- (5) The basis of the leasehold is reduced by any cost or percentage depletion allowed or allowable, while the basis of depreciable equipment is reduced by any depreciation allowed or allowable. In both cases, any abandonment losses deducted, etc., would reduce the adjusted basis. However, partial abandonment losses are not allowable deductions. Although depletion will often exceed the basis in a lease, the basis should not be reduced below zero.
- (6) If any grant of an economic interest in a mineral deposit with respect to which a bonus or advance royalty was received expires, terminates, or is abandoned before there has been any income derived from the extraction of minerals, the grantor must restore to income the depletion deduction taken on the bonus or advance royalty. See Treas. Reg. §§ 1.612-3(a)(2), (b)(2). The grantor must also make a corresponding adjustment to their basis in the minerals.
- (7) Examination techniques found to be helpful in determining the correct basis are as follows:
 - Request the property or leasehold ledger.
 - Determine if all capital expenditures have been added to the cost basis.
 - Review abandonments to ensure that the taxpayer is not prematurely writing off the leasehold or that the taxpayer is not claiming a deduction for a partial abandonment of a lease.
- (8) The following example demonstrates the computation of the adjusted basis for leasehold:

Initial Cost Basis, plus

Subsequent additions (IDC - if elected to capitalize, attorney fees, abstract fees, title search costs, etc.), less

Subsequent reductions (abandonment losses deducted, depletion allowed or allowable, basis claimed as a return of capital in reporting a sale of a partial interest, basis attributable to any portion of the property transferred as a gift, or contribution to corporation or partnership, etc.)

- (9) For dispositions of oil and gas properties to which unamortized IDC (from IRC § 291(b)(5)) exists, the unamortized IDC is treated as a portion of the property's basis, albeit a portion that is not subject to cost depletion. See Rev. Rul. 93-26, 1993-1 C.B. 50. Unamortized IDC stemming from an IRC § 59(e) election should be treated similarly because the elected under amount is properly chargeable to a capital account under IRC § 1016(a)(20). See Treas. Reg. § 1.59-1(b)(2).
- (10) The tax treatment of depletion allowed in excess of the basis of a property sold is explained in Rev. Rul. 75-451, 1975-2 CB 330. Generally, gain on the sale or disposition of property on which percentage depletion has exceeded the basis is limited to the selling price over the adjusted basis of zero. However, the cost of later capital investments in the property must be reduced by the depletion allowed after the adjusted basis was reduced to zero.
- Example:** The taxpayer purchased mineral property for \$1,000,000 and sold it several years later for \$500,000. Prior to the sale, the taxpayer's allowable depletion amounted to \$1,100,000 (this figure includes any cost depletion and percentage depletion taken). The taxpayer's gain would be \$500,000 (\$500,000 sale price - \$0 adjusted basis). However, if immediately before the sale, the taxpayer invested \$300,000 in depletable property, the gain would be \$300,000, the sale price of \$500,000 minus the basis of \$200,000 (\$1,000,000 cost basis + \$300,000 of capital improvements - \$1,100,000 depletion = \$200,000 adjusted basis).
- (11) Upon the disposition after 1975 of certain natural resource recapture property, taxpayers are required to recapture as ordinary income all or some part of the IDC paid or incurred after 1975. For oil and gas properties placed in service before 1987, however, partial recapture of post-1975 IDC is required. For oil and gas properties placed in service after 1986, taxpayers are required to recapture all IDC previously deducted, and depletion deductions that reduced the adjusted basis of the property. See Treas. Reg. § 1.1254-1.
- (12) Section 1254(a)(1) requires that gain is treated as ordinary income in an amount equal to the lesser of "IRC § 1254 costs" or the gain realized on the sale or other disposition. See Treas. Reg. § 1.1254-1(a). The gain realized in the case of a sale, exchange, or involuntary conversion is the excess of the sales price of the property over the adjusted basis. The gain realized on any other disposition is the excess of the fair market value of the property over its adjusted basis. For this purpose, the adjusted basis shall not be less than zero.

Agents should verify this item in most examinations because it is a frequent source of adjustments. Taxpayers should maintain a capital account and a reserve for depletion account for each oil and gas property. All capital investments should be entered in the capital account when the investments are made. All depletion allowed or allowable for income tax should be entered in the reserve account when appropriate. No adjustment is required to either account merely because the reserve account exceeds the capital account. Appropriate adjustments should be made to each account on the disposition of a portion of the property.

For oil and gas property placed in service before 1987, "IRC § 1254 costs" means the amount deducted as IDC after December 31, 1975, reduced by the amount (if any) by which the deduction for depletion under IRC § 611 (computed under either IRC § 612 or IRC §§ 613 and 613A) with respect to the property that would have been increased if the IDC incurred after 1975 had been charged to capital account rather than deducted. Therefore, the amount recaptured is limited to: (1) the amount realized on the sale, exchange, or involuntary conversion, or the fair market value on any other disposition, over the adjusted basis of the property, or (2) the IDC as adjusted above, whichever is the smaller amount. See Treas. Reg. §§ 1.1254-1(1), (b)(1)(ii).

For oil and gas property placed in service after 1986, "IRC § 1254 costs" means the smaller of the aggregate amount deducted as IDC with respect to the property that, but for the deduction, would have been included in the adjusted basis of the property or in the adjusted basis of certain depreciable property associated with the property, plus the depletion deductions that reduced the adjusted basis of the property. No reduction is allowed, however, for the amount (if any) of depletion deduction allowance with respect to the property that would have been increased if the IDC had been capitalized rather than deducted. Compare Treas. Reg. §§ 1.1254-1(b)(1)(i) and (ii).

- (13) Amounts derived from certain dispositions are either limited or excluded from recapture. Such dispositions include transfers by gift, upon death, transfers in certain tax-free reorganizations, like kind exchanges, and involuntary conversions. See Treas. Reg. § 1.1254-2 for a detailed list of the exceptions and limitations. A lease or sublease, however, is not considered a disposition for purposes of IRC § 1254. See Treas. Reg. § 1.1254-1(b)(3)(ii)(C).
- (14) Upon the sale of a portion or an undivided interest of a property, the IDC and depletion deductions with respect to such property must be allocated to the portion or undivided interest in the property to the extent of the gain under IRC § 1254(a)(1). Consult IRC § 1254(a)(2) and Treas. Reg. § 1.1254-1(c) for the rules, limitations, and exceptions of such dispositions.

B.2. Sale of Lease Equipment

- (1) Oil and gas lease equipment is sometimes sold. If the holding period requirement for such equipment is met, any gain or loss resulting from the sale

is subject to IRC § 1231 treatment (capital gain or ordinary loss) and the recapture of depreciation under IRC § 1245.

- (2) Frequently, an entire oil and gas lease will be sold. When this occurs, the sale price must be allocated properly between the lease and the equipment. Usually, the sales contract will specify the sale price of the assets. But, when this is not the case, the sale price should be allocated to the leasehold and the equipment based upon the relative fair market value of each. A petroleum engineer should be requested to make an appraisal of the leasehold and equipment if substantial amounts are involved. See section II.C.11 - Allocation to Leasehold and Equipment Costs, for a full discussion of the allocation techniques.
- (3) One problem frequently encountered when depreciable assets are removed from the equipment warehouse and sold is that the taxpayer's book basis may not indicate the correct tax basis. This is due to the customary practice of valuing equipment removed from a lease based upon its condition. This is done to pay other owners for their percentage interest. Customarily, the equipment will be placed in the warehouse at the appraised value instead of the adjusted basis. For example, equipment may be valued at 75 percent of the replacement cost if it is in good condition and can be used without additional cost or repairs. The joint owners are then paid their share of 75 percent of the new price. The agent should use the original adjusted basis plus the amount paid to the joint owners as the correct basis for purposes of a sale. See section VI.I - Equipment Inventory, for a discussion of the treatment of equipment transfers under joint operating agreements.
- (4) The agent should examine closely the sales instruments used when both the leasehold and equipment are sold to determine if the correct allocation is made between the items. If the taxpayer allocates none of the sales price to the equipment, or less than is properly allocable, the amount of IRC § 1245 gain will be distorted. The agent may obtain an inventory of the equipment sold from the purchaser to use in the verification of the sale price and the basis of the assets sold. The sale of a lease and the related equipment for a lump sum is a potential whipsaw case. In cases in which substantial amounts of money are involved, the agent should make every reasonable effort to obtain consistency of treatment by buyer and seller. The seller's sales price of equipment should be consistent with the amount capitalized to the equipment by the buyer.
- (5) Refer to section II.C.11, Allocation to Leasehold and Equipment Costs for further discussion with emphasis on the buyer.

B.3. Allocation Between Leasehold and Equipment

- (1) The distinction between depletable and depreciable costs is of major importance when a lease is sold. Each seller and buyer will normally attempt to allocate the proceeds for the most favorable tax advantage.
- (2) When a sale of the lease results in a gain, the seller may attempt to assign as much of the sale price to the leasehold as possible. This results in maximizing

its capital gain from the portion of the sale price assigned to the leasehold under IRC § 1231 (excluding the recapture of IDC and depletion under IRC § 1254). Thus, a smaller allocation of the sale price to the equipment sold limits the seller's recapture of depreciation treated as ordinary income under IRC § 1245.

- (3) The purchaser, on the other hand, may attempt to allocate most of the purchase price to the depreciable assets acquired in the sale, thereby assuring a relatively large depreciation deduction in the future. This is especially tempting when percentage depletion is available.
- (4) The buyer and seller may attempt different allocations when the equipment is of high value compared to the lease. This situation may result when a lease and equipment are purchased at or near salvage value. The purchaser will allocate substantially all the purchase price to the leasehold and will then claim cost depletion over a relatively short period of time. The gain from the sale of the salvaged equipment, which will be substantially more than the allocated original cost, will be treated as IRC § 1231 gain and not IRC § 1245 gain. One of the methods used in computing the correct allocation between leasehold and equipment is indicated in Rev. Rul. 69-539, 1969-2 CB 141. In this Revenue Ruling, the price paid for a going mining business must be allocated to each asset or group of assets acquired, including the mineral lease or mineral property, in the proportion that the fair market value of each bears to total fair market value of all the assets acquired.
- (5) In a nontaxable IRC § 351 exchange, the transferee must use the prior owner's basis for depreciation and depletion rather than the actual purchase price and fair market value of the depreciable and depletable assets received. Refer to *Campbell v. Carter Foundation Production Co.*, 322 F.2d 827 (5th Cir. 1963).

B.4. Sale of Fractional Interests in Oil and Gas Leases

- (1) A lease can be sold either in whole or in fractional shares. Fractional interests are normally made up of two types: working interests and royalty interests. The sale of a fractional part of a working interest normally will result in an IRC § 1231 gain or loss.
- (2) The lessee who owns the working interest may assign the property to another and retain an overriding royalty. This transaction would be treated as a sublease, not a sale.
- (3) The original lessee may sell one or more portions of the working interest resulting in the working interest having multiple owners.

Example: The original lessee, *Taxpayer A*, has a $\frac{7}{8}$ working interest (i.e., the landowner retained a $\frac{1}{8}$ royalty interest). Thus, *Taxpayer A* shares all of the expenses and $\frac{7}{8}$ of the production revenue. *Taxpayer A* sells $\frac{1}{2}$ of his working interest to *Taxpayer B*. *Taxpayer B* in turn sells $\frac{1}{4}$ of the $\frac{1}{2}$ of the working interest to *Taxpayer C*. As a result of the sale, *Taxpayer A* owns $\frac{1}{2}$ of the total expenses (or 0.5000) and $\frac{1}{2}$ of $\frac{7}{8}$ of revenue (or 0.4375). Further,

Taxpayer B owns 3/8 of the total expenses (or 0.3750) and 3/8 of 7/8 of revenue (or 0.328125). Lastly, *Taxpayer C* owns 1/8 of total expenses (or 0.1250) and 1/8 of 7/8 of revenue (or 0.109375). If the lessee sells 1/2 of the working interest for a gain, the lessee will report the gain under IRC § 1231.

Example: *Taxpayer D* leased from *Taxpayer E*. *Taxpayer E* retained a 1/8 royalty interest and received a cash bonus of \$20,000 from *Taxpayer D*. *Taxpayer D* in turn sold 1/2 of the 7/8 working interest to *Taxpayer F* for \$11,500. As a result, *Taxpayer D* would have a capital gain of \$1,500 (\$11,500 less 1/2 of \$20,000). All expenses of production would be shared equally by *Taxpayer D* and *Taxpayer F*. *Taxpayer E* (the landowner lessor), would report the \$20,000 bonus as ordinary income. Any income received by *Taxpayer E* from the 1/8 royalty would be ordinary income subject to depletion under IRC § 611 as computed under IRC § 612 or IRC §§ 613 and 613A.

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

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

However, the undivided fraction of the working interest in the remaining tract of land is considered compensation to the operator for under-taking the development project on the drill site. The fair market value of the working interest outside of the drill site is included in the gross income of the operator in the earlier of the year the well was completed or the year the working interest was received by the operator. The original lessee is considered to have sold the undivided fractional interest for the fair market value on the date of transfer. Any resulting gain or loss is subject to IRC § 1231. See Rev. Rul. 77-176, 1977-1 CB 77.

- (5) If a royalty interest in oil and gas is used by the owner in the trade or business, it is not a capital asset and is subject to provisions of IRC § 1231 if held for more than one year.

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

If the royalty is held for sale in the ordinary course of business by a dealer or broker, gain or loss on its sale is ordinary gain or loss. See Rev. Rul. 73-428, 1973-2 CB 303.

- (6) A separate property is formed when two or more property owners contribute their separate properties to form one combined operating "unit" (unitization). In return for the transfer of property rights, the owners receive an undivided interest in the "unit." Such a transfer generally considered an exchange. Frequently, cash is received or paid as an equalization payment in a unitization.

Generally, the cash received will be treated as “boot” in accordance with the provisions of IRC § 1031. See Treas. Reg. § 1.1031(b)-1.

C. Sublease

- (1) A transaction will be classified as a sublease in any case in which the owner of operating rights, or a working interest, assigns all or a portion of those rights to another person and retains a continuing, non-operating interest in production, such as an overriding royalty. Income received in a sublease is ordinary income.
- (2) The pivotal point is to determine whether the retained economic interest in the minerals is a nonoperating interest such as an overriding royalty.

D. Production Payments

- (1) Treas. Reg. § 1.636-3(a) generally defines the term “production payment” as a right to a specified share of the production from mineral in place (if, as, and when produced), or the proceeds from such production. Such right must be an economic interest in such mineral in place and may burden more than one mineral property. The characteristic that distinguishes the production payment from an overriding royalty is that the production payment is limited in dollar amount, quantum of mineral, or a period of time so that its duration is not co-extensive with the producing life of the property from which it is payable. In other words, the expected economic life of the production payment must be shorter than the life of the burdened mineral property or properties.
- (2) There are two types of production payments which are not considered economic interests and are treated as mortgage loans for tax purposes: (1) a retained production payment and (2) a carved-out production payment. A retained production payment is created when an owner of an interest in a mineral property assigns the interest and retains a production payment payable out of future production from the property interest assigned. A carved-out production payment is created when an owner of an interest in a mineral property assigns a production payment to another person but retains the interest in the property from which the production payment is assigned.
- (3) There are several reasons for the use of production payments:
 - Production payments are equivalent economically to nonrecourse financing.
 - Production payments often may be crafted to bridge value perceptions between a buyer and a seller of mineral property.
 - A seller of property who retains a production payment is permitted to attribute reserves to it for financial statement reporting purposes, thus reducing the reserve reduction suffered by selling producing property.

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

D.1. Retained Production Payment

- (1) A production payment that is retained in any transaction except a leasing transaction, occurring on and after August 7, 1969, is treated as a purchase money mortgage and not as an economic interest in the property. Under IRC § 636(c), a production payment that is retained by the lessor in a leasing transaction is treated by the lessee as a bonus payment in installments.
- (2) Under this rule, if a mineral property burdened by a production payment treated as a loan is sold or otherwise disposed of, the seller of a mineral property who retains a production payment will be taxed in the year of sale on the cash consideration received, as well as the outstanding principal balance of the production payment, subject to the installment sales rules. Thus, the seller will immediately realize gain or loss. Compare Treas. Reg. § 1.636-1(c)(1) with Treas. Regs. §§ 1.1274-2 and 1.1275-4(c).
- (3) The purchaser of a property that is subject to a retained production payment as described in (1) and (2) above will be taxed on all income accruing to the property as if the production payment did not exist and will be entitled to depletion on such income. See Treas. Reg. § 1.636-1(a)(ii).

D.2. Production Payments Pledged for Exploration or Development

- (1) If an owner of a mineral property (or properties) carves out and sells a production payment and the proceeds from the sale of the production payment are pledged for the exploration or development of the property (or properties), the production payment is not treated as a mortgage loan to the extent that the taxpayer that created the production payment would not realize gross income from the property absent IRC § 636(a). Compare Treas. Reg. § 1.636-1(b)(1) with Treas. Regs. §§ 1.1273-2 and 1.1275-4(b). It is also necessary that the proceeds be actually used for exploration and development of the property or properties.
- (2) Under the conditions cited above, the seller of the production payment is not required to report and pay income tax on the proceeds, does not have a basis in the proceeds received, and is not allowed a deduction under any section of the Code for the expenditure of the proceeds. If the money is paid for equipment, the taxpayer has no basis in the equipment purchased and no depreciation is allowable.
- (3) Because a production payment that is “pledged for exploration or development” is not treated as a mortgage loan, it is treated as an economic interest in the property (or properties) from which it is paid. The owner of the production payment must report all payments received from the production payment as ordinary income, subject to depletion. The owner of the property (or properties)

from which the production payment was carved has no income as a result of the production and sale of oil and gas used to pay the production payment.

- (4) Because the “carved out” production payment is unique, its sale and subsequent payout may not be reported properly by the taxpayer. Discovery, by examination, of improperly reported production payments is extremely difficult. The existence of a production payment sometimes can be found on the division order. However, some production payments may not be recorded and may not appear on the division order. In these instances, the record owner receives the income and distributes it to the beneficial owner. If a taxpayer is receiving income from a production payment and excluding it from taxable income, the income from the production payment may be found in bank deposits or other books and records. Unreported income of a corporation usually will be shown on Schedule M.
- (5) If a taxpayer has a property on which the income is relatively low compared to operating costs, or the income sharply increases or decreases, it may indicate the existence of a production payment and its creation or termination.
- (6) Corporations usually will report large production payments in the footnotes to the financial statements.
- (7) The agent should ask the taxpayer, or representative, if any of the properties are burdened by production payments.
- (8) If existence of a production payment is discovered and appears material, the agent should study the documents that created the production payment to decide its proper treatment. The agent should then check the taxpayer’s treatment to see that it is proper.
- (9) Since the examination of carved out production payments can be time consuming, the agent should use judgment as to how far this issue should be pursued.

D.3. The Ruling Guidelines

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

- (2) The conditions are:

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

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

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

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

E. Carried Interest

- (1) The term “carried interest” is normally used to define a type of arrangement arising when one party (the “carrying party” or “carrier”) agrees to drill, develop, equip, and operate the working interest owned by another party (the “carried party”). The carrier agrees to pay the carried party’s costs of the property and recover these costs out of the carried party’s share of the oil and gas produced from the property. Various types of carried interest arrangements exist depending on the terms agreed to by the parties which have been examined by the courts.
- (2) In *Herndon Drilling Co. v. Commissioner*, 6 T.C. 628 (1946) the carried party granted the carrying party a fraction of the working interest together with a production payment payable out of the carried party’s retained share of the working interest. The life of the production payment was extended for a period necessary for the recoupment of the carried cost by the carrying party. The Tax Court held that the carrying party was considered to have an economic interest in all of the property from which it would recoup development costs and was thus taxable on all income from that property received as production payments until payout was complete. But, the carrying party could only deduct IDC to the extent of the working interest it actually owned, and not the portion it was assigned in the carried interest transaction. All excess costs were to be capitalized See *also* *Manahan Oil Co. v. Commissioner*, 8 T.C. 1159 (1947).
- (3) In *Commissioner v. J.S. Abercrombie Co.*, 162 F.2d 338 (5th Cir. 1947), the carried party assigned all but 1/16 of the working interest in a property to the carrying party. The carrying party would then pay all costs and expenses for the production and pay the carried party a 1/16 share of the net profits. The Fifth Circuit held the transaction was to be treated as if the carrying party made a loan to the carried party to the extent of the carried party’s cost of equipment, IDC, and operating expenses (if necessary). Thus, the carried party was to be taxed on the income derived from the retained 1/16 working interest, but the carrying party could recoup the costs of production as repayment of loans from carried party’s working interest. The Service acquiesced to this decision in 1949-1 CB 1, which was later withdrawn in 1963-1 CB 5. This decision was specifically overruled by the Fifth Circuit, however, in *United States v. Cocke*, 399 F.2d 433, 22 AFTR 2d 5267 (5th Cir. 1968), rev’g 263 F. Supp. 762, 17 AFTR 2d 888 (DC Tex. 1966).
- (4) In all of the following revenue rulings, the underlying theory is that the “carrying party” must own the working interest until complete payout to be entitled to deduct all of the IDC. If the carrying party owned 100 percent of the working interest during the payout period, then 100 percent of the IDC may be deducted by the carrying party if a proper election was made.

- Rev. Rul. 69-332, 1969-1 CB 87, and Rev. Rul. 71-206, 1971-1 CB 105, deal with the treatment of IDC incurred by a taxpayer who owns less than a full operating interest in an oil and gas well but who is entitled to receive the entire operating interest income until recoupment of all the taxpayer's expenditures.
 - Rev. Rul. 70-336, 1970-1 CB 145, explains the treatment of IDC by a carrying party whose operating interest is subject to a retained overriding royalty that may be converted to a 50 percent operating interest when cumulated gross production equals a specified amount.
 - Rev. Rul. 71-207, 1971-1 CB 160, deals with a situation in which the carrying party who owns the entire operating interest in an oil and gas lease until the carrying party has recouped all of the costs of drilling and completing the well, and thereafter, owns an undivided one-half interest.
 - Rev. Rul. 75-446, 1975-2 CB 95, explains the tax treatment of a carrying party who drills and completes an oil and gas well in return for the entire working interest in the lease until 200 percent of the drilling and development plus the equipment and operating costs necessary to produce that amount are recouped, and after such recoupment relinquishes all rights in the interest to the lessee.
- (5) If the contract omits or allows the exercise of an option to claim a percentage of the working interest before complete payout, the percentage of IDC deductible by the carrying party is affected. The agent should schedule and document the changes in the carried interests because they are a frequent source of tax adjustments.
- (6) In order to know all the facts of a carried interest arrangement, the lease assignments, carried interest agreements, operating agreements, and any letter agreements must be studied. These instruments must be studied due to the different types of arrangements and provisions used to suit the needs of the taxpayer.
- (7) For a discussion of Carried Interests in the context of the Intangible Drilling and Development Cost deduction, see section IV.I.4 – Carried Interest.

E.1. Sale of a Carried Interest

- (1) The question that arises is “how is a sale of a carried interest treated for Federal tax purposes?” There are two sides of the transaction to consider: The “carried party” who has the right to production to recoup the expenditures of IDC, and

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

- (2) If the “carry” is for a period of time less than the entire productive life of the lease, the sale may be viewed as either a carved-out production payment or the sale of a working interest depending upon the facts.
- (3) If a taxpayer sells a lease interest that is burdened with a carry, the taxpayer may be entitled to some capital gain treatment, as was the case in *United States v. Frazell*, where maps were included as part of the property interest. See *United States v. Frazell*, 335 F.2d 487, 14 AFTR 2d 5378 (5th Cir. 1964); *reh. denied*, 339 F.2d 885, 14 AFTR 2d 6119 (5th Cir. 1964), *cert. denied*, 380 U.S. 961.

F. Unitization

- (1) Unitization occurs when two or more persons owning operating mineral interests agree to have the interests operated on a unitized basis. They further agree to share in production on a stipulated percentage or fractional basis disregarding which lease or interest produces the oil and gas. See Treas. Reg. § 1.614-8(b)(6). Unitization may either be voluntary or involuntary. Involuntary unitization may be forced by state conservation laws and regulations. There are various reasons why adjoining property owners unitize their property.
 - Wells can be placed in the most advantageous location, without regard to lease lines, achieving the most economic development and minimizing operation costs.
 - The operating problems involved in secondary recovery methods, such as water flooding, are more easily answered by converting some wells to injection wells.
 - Conservation is aided because the development is fitted to the pools of oil or gas rather than the lease lines.

- (2) The Service's position on unitization follows the "exchange theory", i.e., a unitization affects an exchange of taxpayer's interest in a smaller property or properties for an undivided interest in the unit. See Rev. Rul. 68-186, 1968-1 CB 354. Under this theory, the formation of a unit falls under the single property provision of IRC § 614(b)(3) and constitutes a tax-free exchange of property under the provisions of IRC § 1031 for exchanges started on or before December 31, 2017.
 - IRC § 1031(a) provides that no gain or loss shall be recognized if property held for productive use in a trade or business is exchanged solely for property of a like kind. Therefore, the exchanges of property interests will be deemed to be exchanges of property of a like kind, even though one property may be developed and the other property undeveloped.
 - Gain will be recognized only to the extent of any boot received, whether in the form of cash or other property of unlike kind. Loss from such an exchange shall not be recognized. If the property exchanged was held for more than the required holding period, the recognized gain would qualify for capital gain treatment under IRC § 1231. However, the taxpayer could realize ordinary gain if the property exchanged qualifies as IRC § 1245 property.
 - Loss from such an exchange is not recognized.
 - **Note:** For exchanges started after December 31, 2017, IRC § 1031 like kind exchange treatment applies only to exchanges of real property held for use in a trade or business or for

investment. Real property located in the United States is not of like-kind to real property located outside the United States. Real property held primarily for sale and real property held for personal purposes, such as a taxpayer's residence, do not qualify for like-kind exchange treatment.

- (3) Unitization usually includes not only the mineral interest but also depreciable equipment. Generally, a party to a unitization agreement will have a leasehold cost, which will become the basis for the participating interest in the new unit. If the working interest owner has depreciable equipment, the adjusted basis of the depreciable equipment becomes the basis of the owner's interest in the unitized equipment. Boot received upon the unitization exchange is considered to be received for a sale of property. Thus, gain must be allocated between the equipment and the leasehold.
- (4) Legal fees incurred pertaining to the formation of a unit have been held as deductible expenses and not capital expenditures by the Fifth Circuit. See *Campbell v. Fields*, 229 F.2d 197 (5th Cir. 1956); 48 AFTR 859; 56-1 USTC 54,470).

G. Exchanges of Property

- (1) In general, exchanges of oil property are either taxable or nontaxable depending upon the type of properties exchanged. No gain or loss is recognized when property held for productive use in a trade or business, or for investment, is exchanged solely for property of a like kind, which is also held either for productive use in a trade or business or for investment. See IRC § 1031(a). Since 1975, however, the "recapture rules" of IRC § 1254 may require ordinary income to be recognized in a like kind exchange even if no "boot" or non-like kind property is received. An exchange of "natural resource recapture property" (i.e., mineral property for which IDC or depletion deductions have been taken) for other real property that is not natural resource recapture property (e.g., surface fee interest in land) could require IRC § 1254 recapture of realized gain.
- (2) The nonrecognition rule applies only if the like kind exchange requirements of IRC § 1031(a) are met. Exchanges of property are discussed extensively in Pub. 544, *Sales and Other Dispositions of Assets*. The recapture provision of IRC § 1254 is not discussed in the publication but is covered briefly in the instructions for Form 8824, *Like Kind Exchanges*. This section should be viewed as complementary to that discussion.
 - **Note:** For exchanges beginning after December 31, 2017, IRC § 1031 like kind exchange treatment applies only to exchanges of real property held for use in a trade or business or for investment. Refer to Pub. 544 for details. An interest in oil and gas in place remains an interest in "real property" for federal

income tax purposes. See Rev. Rul. 68-226, 1968-1 CB 362 and Treas. Reg. §§ 1031(a)-3(a)(1) and 1031(a)-3(a)(3).

- (3) If boot is received on the exchange of property, and assuming IRC § 1254 does not require any recapture, then any gain is recognized only to the extent of the boot received. If property is acquired in a like kind exchange, the basis of that property is generally the same as the basis of the property immediately before the transfer (carryover basis). Gain or loss that is not recognized in an exchange of property because of IRC § 1031(a) is generally treated as deferred gain.
- (4) The exchange of a production payment, which is not a continuing interest in an oil property by definition, for any type of continuing interest in minerals is held by the IRS as a taxable exchange. The IRS also holds that a production payment is not like kind property when compared with continuing interest in real estate. Carved-out production payments are generally treated as mortgages and will not qualify in a tax-free exchange.
- (5) Examples of exchanges of property of like kind are as follows:
 - Producing lease for producing lease. See *Laster v. Commissioner*, 43 BTA 159 (1940), aff'd in part, rev'd in part, rem'd, 128 F.2d 4 (5th Cir. 1942). In *Laster*, the Court held that the petitioner's exchange of three producing leases for four like assets was a non-taxable exchange.
 - City lot for minerals. See *Commissioner v. Crichton*, 122 F.2d 181 (5th Cir. 1941). In *Crichton*, the Fifth Circuit held that because mineral rights are an interest in real property under state law, an exchange of mineral rights for an undivided interest in a city lot was a non-taxable exchange.
 - Ranch land and improvements held for business or investment purposes for a working interest. See Rev. Rul. 68-331, 1968-1 C.B. 352). A lessee's interest in a producing oil lease extending until exhaustion of the deposit is an interest in real property. An exchange of such lease for the fee interest in an improved ranch is a like kind exchange, except as to the part of the ranch property consisting of a residence, equipment, and livestock.
- (6) The following examination techniques may be helpful to examiners in determining if an exchange has occurred:
 - Ask the taxpayer to identify all material exchanges of property. Form 8824 should be completed for each exchange. "Multi-asset exchanges" are very common in the oil and gas industry. As stated in the instruction for Form 8824, if the exchange involves multiple assets, the agent needs to make sure the

taxpayer attaches a statement to its return which shows how it determined both the realized and recognized gain.

- Review the depreciation schedules for reductions in different classes of assets.
 - On corporation returns, look to Schedule M or M-3 for income not reported for tax purposes.
 - Review the annual reports, news releases, and internet articles for exchanges.
 - Scan the property ledger.
 - Compare oil lease income from one year to another on a property by property basis, giving attention to large changes. Depletion schedules are useful when comparing gross income.
- (7) Once the agent determines an exchange has occurred, ask the taxpayer for the journal entries pertaining to the transaction to determine if any boot has been exchanged. A taxpayer might improperly consider a taxable exchange to be a nontaxable exchange and reduce the basis by the boot received instead of recognizing it to the extent of the gain as required.

G.1. Like Kind Exchange Issues Unique to Oil and Gas

- (1) Like kind exchanges are very popular in the oil and gas industry. The key reason is that properties typically have high “built-in gain” due to the current deduction of IDC and/or accelerated depreciation of installed equipment. Issues seen by IRS examiners are discussed below.
- (2) Classification of property (e.g., real, tangible personal, intangible). As stated in the introduction to this section, CCA 201238027 concluded that Federal income tax law rather than state law controls in determining whether exchanged properties are of like kind. The position in the CCA should reduce uncertainty over the treatment of exchanges of pipelines in particular, and it should be closely reviewed by examiners. Examiners should also be aware that a producing oil and gas property will have at least two kinds of property:

The mineral rights are an interest in real property.

The lease and well equipment is usually tangible personal property.

- (3) In December 2020, the Service issued final regulations to clarify the definition of “real property” for purposes of applying to exchanges of property after the enactment of the Tax Cuts and Jobs Act of 2017. These regulations include changes that may impact like kind exchanges of oil and gas properties occurring after December 2, 2020 (the effective date of these regulations). Two important changes that examiners should be aware of are:

State and Local Law Test. Under the final regulations, property is real property for purposes of IRC § 1031 if, on the date it is transferred in an

exchange, that property is classified as real property under the law of the State or local jurisdiction in which that property is located. See Treas. Reg. § 1.1031(a)-3(a)(6). Examiners should be aware that these regulations do not adopt the reasoning of CCA 201238027 (cited earlier) to the extent it suggests that State or local law is disregarded in determining whether property is real property under IRC § 1031.

Treatment of Exchanged Machinery and Equipment. Under the final regulations, items of machinery and equipment are characterized as real property if they comprise an inherently permanent structure, a structural component, or are real property under the State or local law test. See Treas. Reg. § 1.1031(a)-3(a)(2). This means that some types of property that were historically treated as tangible personal property may now be treated as real property in like kind exchanges.

- (4) The regulations provide industry specific examples of “inherently permanent” real property under IRC § 1031: oil and gas pipelines; offshore platforms, derricks, and oil and gas storage tanks. See Treas. Reg. § 1.1031(a)-3(a)(2)(ii)(C). For assets not specifically enumerated, the regulations provide a set of factors for analyzing each “distinct asset” to determine if the property meets the “inherently permanent” requirements necessary to qualify as real property. Example 9 in the final regulations demonstrates how this analysis is applied to the distinct assets that make up a “pipeline transmission system”. The analysis reaches a conclusion about three distinct assets: (1) underground pipelines are deemed real property, (2) isolation valves and vents are deemed real property, and (3) meters and compressors are not real property.
- (5) In summary, under the final regulations, property is classified as real property for purposes of IRC § 1031 if the property meets any of the following three definitions:
 - (1) Classified under the State and local law test, subject to certain exceptions,
 - (2) Specifically listed as real property in the final regulations, or
 - (3) Considered real property based on all the facts and circumstances under the various factors provided in the final regulations.

Note: In applying these definitions, determining whether an asset is classified as real property is analyzed separately from any other asset to which it relates. In addition, property classified as real property under one of the definitions discussed above may be like-kind to other real property defined under another definition. Finally, a determination that property is personal property under State or local law under § 1.1031(a)-3(a)(6) does not preclude the conclusion that property is real property as specifically listed in § 1.1031(a)-3(a)(1), (2) or (3), or under the factors listed in § 1.1031(a)-3(a)(2). Contact the DCE Practice Network for assistance in the examination of kind exchanges.

- (6) Where multiple properties are transferred in an exchange, the gain recognized is calculated using the FMV of each property transferred and received in an exchange group. If a difference exists between the allocation of FMV to the property (minerals and equipment) transferred and received in an exchange group, any gain realized is recognized to the extent of the lesser of (1) the gain realized, or (2) the exchange group deficiency, if any. The exchange group deficiency is the excess of the aggregate FMV of the properties transferred in an exchange group over the aggregate FMV of the properties received in that exchange group. See Treas. Reg. § 1.1031(j)-1(b).
- (7) An issue exists where a taxpayer inappropriately assumes that all producing properties that are part of an exchange (transferred and/or received) have the same relative percentage of FMV allocable to minerals and equipment resulting in the deferment of built-gain on the exchange. For example, assuming that, for each and every property exchanged and received, the FMV is comprised of 80 percent minerals and 20 percent equipment is inappropriate unless supported by the facts. Generally, properties that use expensive production equipment tend to have a higher-than-normal portion of their FMV represented by equipment. An IRS engineer may be needed to review the determination of FMV and its allocation.

Note: Under the Tax Cuts and Jobs Act of 2017, only real property held for the productive use in a trade or business or for investment qualifies for like-kind exchange treatment.

Example: Property A has a FMV of \$1,000 that is comprised of minerals worth \$800 and equipment worth \$200. Assume the taxpayer has an adjusted basis of \$50 in each for a total basis of \$100. Property A is exchanged for Property B which has a FMV that is comprised of minerals worth \$900 and equipment worth \$100. Looking at the equipment exchange group, the taxpayer gave up \$200 worth of equipment but received only \$100 worth of equipment in return. That creates an exchange group deficiency of \$100, which can be viewed as being satisfied by the receipt of \$100 of minerals (not of like kind). Gain on the transfer of equipment, computed in accordance with Treas. Reg. § 1.1031(j)-1(b)(3)(i), is \$150: the difference between the FMV of the exchange group property transferred (\$200) and its adjusted basis (\$50). The amount of gain which must be recognized, however, is \$100, which is the lesser of the exchange group deficiency (\$100) and the gain on the transfer of the exchange group property (\$150). The fact the value of minerals received (\$900) is more than the value of minerals transferred (\$800) is immaterial.

Example: Property C has FMV of a \$1,000 that is comprised of minerals worth \$800 and equipment worth \$200. Assume the taxpayer has an adjusted basis of \$50 in each for a total of \$100. Property C is exchanged for Property D which has a FMV that is comprised of minerals worth \$700 and equipment worth \$300. Looking at the *minerals* exchange group, the taxpayer gave up \$800 worth of minerals but received only \$700 worth of minerals in return. That creates an exchange group deficiency of \$100, which can be viewed as being

satisfied by the receipt of \$100 in equipment (not of like kind). Gain on the transfer of minerals, computed in accordance with Treas. Reg. § 1.1031(j)-1(b)(3)(i), is \$750 which is difference between the FMV of exchange group property transferred (\$800) and its adjusted basis (\$50). The amount of gain which must be recognized, however, is \$100 which is the lesser of the exchange group deficiency (\$100) and the gain on the transfer of the exchange group property (\$750). The fact the value of equipment received (\$300) is more than the value of the equipment transferred (\$200) is immaterial.

Note: Under the Tax Cuts and Jobs Act of 2017, only real property held for the productive use in a trade or business or for investment qualifies for like-kind exchange treatment.

- (8) The above examples show that an exchange group deficiency exists when the acquired Property B has more *or* less value in its minerals than Property A. Only when Property B's FMV allocation between minerals and equipment matches Property A's would no exchange group deficiency exist, and therefore no built-in gain would be recognized. Examiners have seen taxpayers use artificially standard allocations of FMV in order to inappropriately defer the recognition of gain that was realized upon the exchange.

G.2. Exchanges Involving Natural Resource Recapture Property

- (1) Section 1254 and Treas. Reg. § 1.1254-1 provide a rule that overrides the nonrecognition provisions of IRC § 1031.

Under IRC § 1254(a), if "Section 1254 Property", including natural resource recapture property, is disposed of, gain is recognized as ordinary income to the extent of the lesser of (1) deducted IDC and depletion which reduced the basis of the property, or (2) the amount realized, or the fair market value of the property, over the adjusted basis of the property.

In general, "natural resource recapture property" includes any mineral property for which either IDC (other than for nonproductive wells) or depletion was deducted. An exchange of such property with built-in gain for like kind property that is not natural resource recapture property (such as a fee interest in surface land) results in the realization of gain. Such gain must be recognized as ordinary income to the extent of "IRC § 1254 costs".

Section 1254 costs are generally the sum of IDC deducted under IRC §§ 263(c), 59(e), or 291(b) (but not for drilling of nonproductive wells) and depletion deductions under IRC § 611 which reduced the property's basis (i.e., the percentage depletion claimed after the recovery of basis is not included). See Treas. Reg. § 1.1254-1(b)(1)(ii) for a different formula if the property had been placed in service before 1987.

- (2) Treas. Reg. § 1.1254-1(b)(3) provides that a "disposition" for purposes of IRC § 1254 does not include certain transactions common in the oil industry including the creation of a production payment under IRC § 636, a lease or sublease, and any unitization or pooling arrangement, among other transactions.

- (3) Treas. Reg. § 1.1254-2(d)(1) limits the amount of gain recognized under IRC § 1254 upon the disposition of natural resource recapture property in a like kind exchange or involuntary conversion to the amount of gain recognized on the disposition, plus the fair market value of non-natural resource recapture property. Treas. Reg. § 1.1254-2(d)(2) provides rules for determining the amount realized when natural resource recapture property and non-natural resource recapture property are both acquired and disposed of in a like kind exchange or involuntary conversion. The basis of the properties received is determined under IRC § 1012 (cost basis) and allocated to each property according to its respective fair market value. See Treas. Reg. §§ 1.1254-3(a)(1), 1.1031(j)-1.
- (4) Treas. Reg. § 1.1254-3 addresses the treatment of IRC § 1254 costs immediately after certain transactions. Generally, when property that is natural resource recapture property is both disposed of and acquired in a like kind exchange or involuntary conversion, an assignment of the IRC § 1254 costs of the disposed property is made to the acquired natural resource recapture property. See Treas. Reg. § 1.1254-3(d). The amount assigned is the IRC § 1254 costs of the disposed property minus the amount of ordinary income recognized under IRC § 1254(a)(1).
- (5) The following example demonstrates the principles of the regulations:
- A taxpayer disposes of the following property in a like kind exchange:
- Property A, which is a natural resource recapture property with a fair market value of \$1,000. Property A has a placed-in-service date of 1991. It has an adjusted basis of \$100. Depletion of \$300 was taken in computing the adjusted basis. The total amount of intangible drilling and development costs deducted with respect to this property was \$200.
- A taxpayer acquires the following property in exchange:
- Property B, a natural resource recapture property with a FMV of \$700 and Property C, which is surface land and not a natural resource recapture property. Property C has a FMV of \$300.
- The taxpayer's Property A had a built-in gain of \$900 which is the difference between the FMV of \$1,000 and the adjusted basis of \$100. Since it was placed-in-service after 1987, its IRC § 1254 costs are \$500 (depletion of \$300 plus IDC of \$200). If Property A were sold, the gain recognized would be bifurcated into \$500 of ordinary income (IRC § 1254 recapture) and \$400 of capital gain. However, because it was exchanged for properties that were all like kind, Treas. Reg. § 1.1254-2(d)(1) limits the amount to be recaptured under IRC § 1254(a)(1) to \$300 (the FMV of the surface land, non-natural resource recapture property).
- After the exchange is complete, Treas. Reg. § 1.1254-3(d) requires the taxpayer to assign the remaining \$200 of IRC § 1254 costs (\$500 of IRC § 1254 costs attributable to disposed Property A minus \$300 that the taxpayer

recognized as ordinary income) to Property B, the natural resource recapture property acquired. The taxpayer's basis in the two acquired properties (B and C) is \$400, the sum of the basis it had in Property A plus the \$300 of ordinary income it recognized. Since Property B and Property C are both like kind to Property A, the taxpayer must allocate basis to Properties B and C based on the properties' relative fair market value. Accordingly, 70 percent (\$700 divided by \$1,000) of the \$400 (\$280) is allocated to Property B so that it has basis of \$280 and 30 percent (\$300 divided by \$1,000) of the \$400 (\$120) is allocated to Property C.

H. Capital Gain Versus Ordinary Income

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

H.1. Seller is a Dealer

- (1) Lease brokers are common in oil and gas producing areas. If the property sold is held by a broker for sale in the normal course of the business activity, the taxpayer will be considered a dealer and the income will be ordinary income. Section 1231 will apply, however, to the gains from the sale of leases by a dealer or broker if the dealer can establish that the property was held for investment purposes only. Therefore, some taxpayers may be both a dealer and an investor.
- (2) Rev. Rul. 73-428, 1973-2 CB 303, addresses the tax treatment of a sale of a royalty interest in oil and gas in place. If the interest is used by the owner in their trade or business, it is not a capital asset but will be subject to the provisions of IRC § 1231 if held for the required length of time. If the royalty is held for investment, gain or loss on its sale is a capital gain or loss. If the royalty is held for sale in the normal course of a taxpayer's business, ordinary gain or loss will result.
- (3) The courts have used various factors in determining whether an individual is a dealer or an investor. Listed below are two cases which highlight these factors.
- (4) In *Spragins v. United States*, 42 A.F.T.R.2d 78-5389 (N.D. Tex. 1978); 42 AFTR. 2d 78-5389; 78-1 USTC 84,323, the Court decided that the taxpayer held certain oil and gas leases for investment not for sale in the ordinary course of business. Thus, the taxpayer was entitled to capital gain treatment. The court found that the taxpayer was primarily an oil and gas producer, did not advertise leases for sale, and that most of his gross income came from 31 producing oil and gas properties was determinative in finding the properties were not held for sale in his ordinary business activity, but were instead held for investment.
- (5) In *Bunnel v. United States*, 20 A.F.T.R.2d 5696 (D. N.M. 1968), a jury determined that oil and gas leases had been held by the taxpayer primarily for sale to customers in the ordinary course of business. Therefore, gain realized upon the sale of leases was subject to treatment as ordinary income instead of capital gain. In the above case, the jury was charged to consider the following

facts in making their determination, which the examiner may find helpful. No single factor is controlling in determining if the property is held for sale to the customer in the ordinary course of business and consideration must be given to all the facts.:

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

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

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

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

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

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

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

H.2. Seller is an Investor

- (1) The producer or casual investor will usually buy royalty interests with the hope that oil or gas production will be obtained. If there is production or even good prospects of production, an investor may receive an offer to sell. This sale would qualify for capital gain treatment provided the property was held for the required length of time.
- (2) An investor will sometimes trade a fractional interest in a royalty for an interest in another royalty. This type of transaction follows the like kind exchanges under IRC § 1031(a) and any gain realized is recognized only to the extent of the money or unlike property (boot) received.
- (3) Some techniques to be used in auditing an investor in royalties is to note all credits to the royalty asset accounts and determine their nature. This may reveal a transaction not otherwise shown by a purchase or sale. Accounts in the spouse's name should be examined for items which might represent unreported income. If a loss is shown on the sale of a royalty, determine if there has been any write-off for abandonments, etc., in prior years. Be alert to those situations

where a fractional part of an interest is sold. The cost of the entire interest may be shown as the basis for the part sold. Also, remember that any depletion claimed (percentage or cost) must be applied to reduce the basis. A nonproducing property may be under an existing lease for which the taxpayer received a bonus on which depletion was taken. In the termination of the lease, the depletion on the bonus should be restored to income; however, depletion on the bonus is not required when a property is merely transferred. See Rev. Rul. 60-336, 1960-2 CB 195.

H.3. Sale of Geological and Geophysical (G&G) Data

- (1) Geological and Geophysical (G&G) data obtained through exploratory and seismic activities is frequently exchanged and/or sold to other parties interested in the hydrocarbon potential of a given area. Brokers are active in the sales, swaps, and exchanges of this data. The seismic data usually is recorded on magnetic tapes.
- (2) There are a number of companies that gather G&G data for the purpose of selling it to other parties interested in exploring for oil and gas. A seismic survey company acquires G&G data through various means. In some cases, a seismic survey company will on a speculative basis incur all the cost to conduct a “shoot” (data acquisition survey) in a geographical area and attempt to sell the “spec” data to as many interested parties as possible. In other arrangements, the seismic survey company will organize operators who are interested funding a seismic survey in certain geographic areas and to have proprietary rights to the data.
- (3) G&G expenditures are subject to amortization under IRC § 167(h). Regarding taxpayers that are not oil and gas operators, the Tax Court in *CGG Americas, Inc. v. Commissioner*, 147 T.C. 78 (2016), found that a corporation that incurred expenses for geophysical surveys and then licensed the data from the surveys to its customers was entitled to amortize the expenses over 24 months under IRC § 167(h).
- (4) It appears that seismic survey companies that buy, sell, and trade G&G data would be subject to IRC § 167(h)(4) which states that “if any property with respect to which geological and geophysical expenses are paid or incurred is retired or abandoned during the 24-month period described in paragraph (1), no deduction shall be allowed on account of such retirement or abandonment and the amortization deduction under this subsection shall continue with respect to such payment”.
- (5) See LAFAs 20163501F where a taxpayer could not include unamortized G&G amounts in the basis of an oil and gas property for purposes of computing gain or loss. Nor could the taxpayer immediately deduct the remaining amortizable G&G expenses that it paid or incurred in connection with the exploration and development of the properties. Instead, the taxpayer was required to deduct the remaining G&G in accordance with the original IRC § 167(h) amortization schedule.

- (6) An examiner that identifies transactions involving G&G data should develop the facts and contact IRS Counsel.

I. Worthless Minerals

- (1) Section 165 allows a deduction for losses not compensated for by insurance or otherwise if incurred in a trade or business or any transaction entered into for profit though not connected with the taxpayer's trade or business. The losses must be evidenced by a closed and completed transaction or a fixed, identifiable event that establishes that the property has become worthless. The taxpayer must substantiate two facts:
- First, that some event during the taxable year established the worthlessness of the property, and
 - Second, that no event had occurred in a prior year that had established its worthlessness in a prior year. A formal disposition of the interest in the property is not required if worthlessness can be proven by any other means. See Rev. Rul. 54-581, 1954-2 CB 112.
- (2) The closed transaction that most clearly establishes worthlessness of oil and gas properties is the relinquishment of title. This can be accomplished by nonpayment of delay rentals, surrender of leases, or a release recorded with a governmental municipality in the appropriate records.
- (3) An identifiable event that may prove an oil and gas property worthless is the drilling of a dry hole on or near the property. In each case, it is a question of fact as to whether the dry hole does or does not condemn the property as worthless. Usually, the agent should consult an engineer concerning worthlessness. See *Goodwin v. Commissioner*, 9 BTA 1209 (1928); *acq.*, VII-1 CB 12.
- (4) A loss deduction is not allowed for shrinkage in value. In *Louisiana Land & Exploration Co. v. Commissioner*, 7 T.C. 507 (1946), *acq. on other issues*, 1946 2 CB 3, *aff'd*, 161 F.2d 842 (5th Cir. 1947), 35 AFTR 1388, 47-1 USTC 9266, the taxpayer purchased a tract of land for \$30,000. The main purpose was to purchase the mineral rights, and the taxpayer allocated \$15,000 to mineral rights and \$15,000 to surface rights. During the year, the taxpayer's lessee drilled a dry-hole and forfeited the lease and the taxpayer retained ownership in the surface rights. Under these facts the court denied the deduction for worthlessness of the minerals.
- **Note:** In cases where the mineral and surface rights have separate values for estate purposes, the findings may be different.
- (5) In *Lyons v. Commissioner*, 10 T.C. 634 (1948), a deduction for partial worthlessness was denied because the taxpayer had several wells on one tract and abandoned some of the wells. The tract was viewed as one unit.

- (6) In *Gulf Oil Corp. v. Commissioner*, 87 T.C. 135 (1986), *aff'd*, 914 F.2d 396 (3d Cir. 1990), and *Phillips Petroleum Co. v. Commissioner*, T.C. Memo. 1991-257, the interrelationship between a determination of worthlessness and an overt act of abandonment was addressed at length. These cases should be reviewed closely especially if a taxpayer claims an abandonment loss for any portion of an operating interest while still retaining rights to explore, develop, or produce from the property.
- (7) Section 465 generally provides that the amount of loss otherwise allowable with respect to an activity cannot exceed the aggregate amount which a taxpayer has at risk with respect to such activity at the close of the taxable year. Each separate oil and gas property is treated as a separate activity for purposes of IRC § 465. See IRC § 465(c)(2)(a)(iv).

I.1. Examination Techniques

- (1) The examiner, in the beginning of the examination, should obtain a list of canceled leases showing project identification, lease identification, cost, and date acquired. Verify the bases of the leases canceled and determine if any portion of any one of the leases written off is in a unitization project.
- (2) Determine if the property charged off has been top leased in a subsequent year and check to see if title to the property is still held by the taxpayer. An easy way to do this is to check delay rentals paid on the leases that have been abandoned.
- (3) The allowance of a deduction for worthlessness should not be based on the consideration of only one or two factors. The determination can only be made when all of the facts are known.

J. Worthless Securities in Oil and Gas Examinations

- (1) Under IRC § 165(g), if a security which is a capital asset becomes worthless during the taxable year, the loss resulting therefrom shall be treated as a loss from the sale or exchange from a capital asset on the last day of the taxable year. The worthlessness of a security is an objective determination looking at all the facts and circumstances. See *Boehm v. Commissioner*, 326 U.S. 287 (1945). When a security becomes worthless is determined by reference to identifiable events which evidence the destruction of both the actual and potential value of the security in the year the loss is claimed. See *Lincoln v. Commissioner*, 24 T.C. 669 (1955), *acq.*, 1956-2 CB 4, *aff'd*, 242 F.2d 748 (1957).
- (2) The deduction for worthless securities under IRC § 165(g) is often used by some taxpayers to account for losses derived from unsuccessful wells. Typically, a CFC will be created by a parent corporation or domestic subsidiary to coincide with the acquisition of acreage, which is typically in the form of a "concession" from a foreign country. The costs of acquiring and drilling the wells within the concession are treated as contributions of capital to the CFC. When the taxpayer determines that the well or wells drilled within the concession are

not commercially productive, a decision is made to release the concession back to the foreign government. The parent dissolves the CFC, claims its basis in the stock of the CFC as worthless, and takes an ordinary loss deduction from income. This deduction is generally a U.S.-sourced loss for the domestic entity.

- (3) Losses from affiliated corporations, which meet the requirements of IRC § 1504(a)(2), may be allowed ordinary treatment instead of capital. In order for a worthless securities loss to be considered an ordinary loss, IRC § 165(g)(3)(b) requires that more than 90 percent of the gross income of the loss corporation be from non-passive type activities. Taxpayers have taken the position that the ordinary test is met if the corporation has no income, as long as the activity of the corporation is that of an operating company. The Service agreed with that position in TAM 200914021, concluding that the gross receipts test of IRC § 165(g)(3)(B) does not preclude a taxpayer from deducting an ordinary loss for the worthless stock of a wholly owned operating company that never received any gross receipts.
- (4) For further requirements, examiners should review the appropriate issue guidance posted on internal websites, such as foreign joint ventures, foreign partnerships, and check-the-box.

J.1. Examination Techniques of Worthless Securities

- (1) Examiners should review the criteria for claiming a worthless stock loss and consider whether all of the requirements are met in the year the worthless stock loss is claimed. For example, verify whether the year of release or expiration of the concession coincides with the year of the deduction and whether there was dissolution of the CFC in the year of the deduction or another identifiable event that fixes the loss. Examiners should be aware that a common feature of foreign oil and gas concessions is that they decrease in size as exploration activity delineates the reservoir, but the Service would not allow a deduction for worthlessness as long as the taxpayer retained rights to some portion of the concession. Additionally, examiners should verify that the taxpayer has fulfilled all of its obligations, such as conducting seismic surveys and drilling wells, required by the concession agreements or association agreements.
- (2) Examiners should also review the accuracy of the basis computation of the stock in the loss corporation in determining the amount of the loss.
- (3) Examiners should be aware that some taxpayers claim worthless deductions for stock in newly formed CFCs that acquire tracking interests in operating companies. More specifically, certain taxpayers:
 - create a separate CFC for each well from a concession (or grouping of wells from different concessions into a single CFC);
 - cause the CFC to acquire tracking stock (or another class of stock) that reflects the performance of a specific well (or specific wells); and
 - claim a worthlessness deduction for stock in the CFC if the traced wells are not productive.

- (4) In considering all of the facts and circumstances with regard to any such worthless stock deduction, review the underlying worthlessness of the property and the economic realities of the structuring (including whether the CFC paid fair market value for the tracking interest). Contact Local Counsel or a Subject Matter Expert for case development suggestions on tracking stock issues.

K. Abandonment of Lease

- (1) Lease costs usually are deducted from gross income in the year of abandonment. Usually, the year of abandonment will coincide with the year that the property becomes worthless. However, if the situation arises in which the property becomes worthless prior to the overt act of abandonment, the Service considers the year in which worthlessness is established to be the controlling year. "It is held that an abandonment loss is deductible only in the taxable year in which it is actually sustained. An abandonment loss which was actually sustained in a taxable year prior to the year in which the overt act of abandonment took place is not allowable as a deduction in the latter taxable year." Rev. Rul. 54-581, 1954-2 CB 112.
- (2) The taxpayer may purchase a large amount of acreage in a single property and later attempt to abandon part of the acreage that is undesirable. This type of abandonment is called a partial abandonment. A partial abandonment loss is not allowable, an abandoned loss can be claimed only when the entire property is abandoned.
- (3) The abandonment of nonproducing property has, in fact, occurred when a delay rental payment is not made by the due date. Usually, the loss will be the cost of the property since there should be no deduction claimed for depletion, partial abandonments, etc.
- (4) The abandonment of producing properties could be a problem for the examiner. If the property has been producing, the logical question to ask is, "Why does the taxpayer have a loss on abandonment?" Usually, if the reserves have been correctly determined on the property, a taxpayer should have recovered the cost basis by either percentage or cost depletion. Since the taxpayer is entitled to cost depletion, if the lease has run its normal life, the entire cost should have been recovered. See *James Petroleum Corp. v. Commissioner*, 24 T.C. 509 (1955), *aff'd*, 238 F2d 678 (2d Cir. 1956), *acq.*, 1956-1 CB 4, *cert. den'd*, 353 U.S. 910 (1957). However, a property may become unprofitable before the basis is recovered. The examiner must obtain all of the facts.
- (5) Expiration under the terms of the lease is considered to be an abandonment if there is no extension of the lease. Under the terms of the lease, the taxpayer may be allowed to operate the lease for a specific time (e.g., 10 years) or may have an option to extend the lease for a specific time. The examiner should scrutinize the terms of the lease. If the lease has no options to extend or if the options have not been exercised, the abandonment should be allowed. In allowing an abandonment due to expiration under the terms of the lease, the agent should be aware of the possibilities of top leasing.

K.1. Examination Techniques

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

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

Does the lease expire on a certain date?

Are there any options to renew?

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

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

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

K.2. Forfeit of Lease

- (1) A forfeit of a lease may occur when the production of the lease falls to the point where it is not profitable to continue the lease. In a productive lease agreement, the terms generally call for forfeiture of the lease 90 days after production stops. In a nonproductive lease, the forfeiture of the lease may occur when the taxpayer fails to pay the delay rental.
- (2) Examiners should be aware that, in general, delay rentals are not based on a calendar year.

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

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

K.3. Top Lease

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

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

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

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

- (3) See section II.C.8 – Top Leasing, for additional discussion of this topic.

L. Sale of Scrap Equipment

- (1) The gain on sale of scrap equipment such as pipes, pumps, and tanks will depend on how the taxpayer defines the term "scrap equipment."
- (2) If the taxpayer defines scrap equipment to include usable equipment that can be used in other oil and gas endeavors, the gain will be considered IRC § 1231 gain on the sale of an asset used in a trade or business subject to IRC § 1245 recapture. If the taxpayer is using an alternative depreciation range (ADR) method of depreciation, the agent will need to determine if the gain or loss is normal or abnormal. Abnormal (extraordinary) gains or losses for ADR are subject to the tax treatment of IRC § 1231 and IRC § 1245 recapture. Normal retirements resulting in gains or losses will not be reported as income but will affect the asset reserve.
- (3) If the taxpayer defines the term "scrap equipment" to include unidentified equipment and parts not usable in future oil and gas development, gain from the sale of scrap equipment is treated as ordinary income.

M. Engineering Referrals

- (1) When an agent encounters an engineering problem and referral to an engineer is not mandatory under IRM or local directives issued thereunder, the agent may still request the services of an engineer. Discussion with the group manager is appropriate. In many cases, an informal discussion with an engineer can solve the problem. However, when necessary, a referral can be made using the Specialist Referral System.
- (2) Some of the issues an agent may encounter in which an engineer's services would be helpful are listed below:
 - Worthlessness

- Abandonment
 - Valuations of leasehold and equipment
 - Depletion
- (3) Instructions for mandatory referral of oil and gas issues to engineers vary from Territory to Territory. Agents should follow local guidelines.

IX. Issues in Oil and Gas Transportation

A. Pipeline Right of Way

- (1) Effective March 8, 1971, the Service modified an earlier ruling and announced its current position on high pressure natural gas pipeline right-of-way easements, clearing, and grading costs. See Rev. Rul. 71-120, 1971-1 CB 79. The same position was announced for crude oil and petroleum products pipeline costs in Rev. Rul. 71-448, 1971-2 CB 130.
- (2) These rulings hold that easement costs (including aerial reconnaissance, preliminary surveys, the initial costs of clearing and grading, roddage fee payments to the grantor based on length of the easement, crop damage reimbursement, legal fees, title work, abstract and recording fees, etc.) have a determinable life measured by the useful life of the pipeline and are, therefore, depreciable. Since easement costs are similar to a license or franchise, they are considered an intangible asset and will not qualify for any accelerated depreciation. Depreciation of right-of-way costs must be calculated using the straight-line method. See *Panhandle Pipe Line Co. v. U.S.*, 408 F.2d 690 23 AFTR 2d 933 (Ct. Cl. 1969).
- (3) Rev. Rul. 72-403, 1972-2 CB 102, modifies these rulings to hold that, while the above-mentioned easement costs, including the initial costs of grading and clearing, are depreciable, only the initial costs of clearing and grading the right of way qualify for accelerated depreciation methods and investment credit are not included in any of the asset guideline classes for ADR purposes. Under Rev. Proc. 87-56, 1987-2 CB 674 (for MACRS property), initial clearing and grading land improvements as specified in Rev. Rul. 72-403, are excluded from asset class 00.3, Land Improvements, asset class 46.0, Pipeline Transportation, and asset class 49.24, Gas Utility Trunk Pipelines and Related Storage Facilities. The American Jobs Creation Act of 2004, however, added IRC § 168(e)(3)(E)(iv), which provides that 15-year MACRS property includes initial clearing and grading land improvements with respect to gas utility property.
- (4) The costs for the easement and for clearing and grading referred to above do not include expenditures incurred to keep the right of way clear and the pipeline in its normal operating state. Whether such expenditures are ordinary and necessary expenses or capital expenditures requires a determination based on facts and circumstances of each case.

B. Inventory in the Pipeline

- (1) In order to maintain pressure and effect uninterrupted flow or transportation of natural gas to purchasers through pipelines, it is necessary to maintain a certain volume of gas in the lines at all times. This volume of gas is called “line pack” by the industry. Some taxpayers will expense this cost as ordinary and necessary business expense. Some may attempt to capitalize this cost as part of the pipeline cost and depreciate it over the life of the pipeline. The IRS position regarding the treatment of these expenses is explained by Rev. Rul. 97-54, 1997-2 CB 23, which holds the cost of recoverable line pack gas is a non-depreciable capital expenditure, while the cost of nonrecoverable line pack gas is a depreciable capital expenditure. Line pack gas is recoverable to the extent such gas will be recovered from an abandoned pipeline or storage reservoir pursuant to a plan, a requirement of law, or economic feasibility, whichever method projects the greatest actual recovery of such gas. *See also Arkla, Inc. v. United States*, 765 F.2d 487, 490 (5th Cir. 1985).
- (2) Charges incurred by retail gas utilities obtaining natural gas for resale are includable inventory costs. These costs include damage charges, capacity charges, injection charges, storage charges, withdrawal charges, and delivery charges, among others. *See Rev. Rul. 66-145*, 1966-1 CB 98.
- (3) While it is true that only oil will be flowing through the pipeline, different grades of oil may be in the pipeline at the same time. It is possible to space different grades of oil by running a cleaning tool (called a pig) and a water spacer between each type of oil. In this manner, it is possible to have many different types of petroleum products in the pipeline at yearend. Therefore, it is necessary to determine, with the help of a petroleum engineer, not only the quantity of the oil in the pipeline but also the type of oil. Once the quantity of the specific types of oil is determined, then the correct price must be applied to arrive at the correct ending inventory.
- (4) In examining a pipeline, the agent should first determine what type of line is in use (gas or oil). Determine how the taxpayer handles the line pack or oil in the line expensed, capitalized, or inventoried. If the costs are inventoried, determine whether all costs pertaining to the inventory are included. If the taxpayer has an oil line, ensure that the costs taken into inventory reflect the correct costs based on the correct type of oil. It is possible that the taxpayer, while correctly including the oil in inventory, may have assigned one cost for the entire oil in the pipeline while, in reality, different prices should have been used since different oils were in transit at year end.

C. Alaska Pipeline Depreciation

- (1) Section 168(e)(3)(C) defines 7-year property to include any Alaska natural gas pipeline. The term “Alaska natural gas pipeline” refers to the pipe, trunk lines, related equipment, and appurtenances used to carry natural gas but does not include any gas processing plant located in the state of Alaska which has a capacity of 500 billion Btu of natural gas per day and is placed in service after

December 31, 2013. If the system is placed in service prior to January 1, 2014, the taxpayer may elect to treat the system as placed in service on January 1, 2014, to qualify for the 7-year recovery period. If placed in service prior to January 1, 2014, and the election is not made, the taxpayer would have a 15 or 20-year recovery period depending on when the property was placed in service. If elected, depreciation would not begin until after 2013.

- (2) This incentive provision is effective for property placed in service after December 31, 2004.

D. Natural Gas Line Depreciation

- (1) Gas distribution lines must be depreciated over 15 or 20 years depending on when the lines were placed in service:
 - Placed in service after April 11, 2005 and before January 1, 2011 - 15 years. See I.R.C. § 168(e)(3)(E)(vi).
 - Placed in service on or before April 11, 2005, or on or after January 1, 2011 - 20 years. See Energy Policy Act of 2005, Pub. L. 109-58, 119 Stat. 594, § 1325 (Aug. 8, 2005).
 - **Note:** The 15-year provision (added by the Energy Policy Act of 2005) does not apply to property subject to a binding construction contract or self-constructed on or before April 11, 2005.
- (2) Natural gas gathering lines must be depreciated over a 7-year recovery period (14-year class life) under the Energy Policy Act of 2005. In addition, the Energy Policy Act of 2005 provides for no adjustment for the allowable amount of depreciation for alternative minimum tax purposes. The 7-year provision does not apply to any property which the taxpayer or related party had entered into a binding contract for the construction thereof on or before April 11, 2005, or in the case of self-constructed property, has started construction on or before April 11, 2005.
- (3) A natural gas gathering line is defined by IRC § 168(i)(17) to include any pipe, equipment, and appurtenance that is determined to be a gathering line by the Federal Energy Regulatory Commission and is used to deliver natural gas from the wellhead or a common point to the point at which such gas first reaches:
 - a gas processing plant,
 - an interconnection with an interstate transmission line,
 - an interconnection with an intrastate transmission line, or
 - a direct interconnection with a local distribution company, a gas storage facility, or an industrial consumer.

X. Activities and Personal Services Provided on the U.S. Outer Continental Shelf

A. In General

- (1) The U.S. Outer Continental Shelf (OCS) is the continental shelf adjacent to U.S. territorial waters over which the United States has the exclusive right of exploring for and exploiting natural resources.
- (2) Vessel owners (including vessel charterers in the chain between the vessel owner and the operator) and vessel operators may be engaged in activities related to the exploration for, or exploitation of, natural resources on the OCS. These activities include, for example, seismographic testing, drilling services, repair and salvage work, and the transportation of supplies and personnel between U.S. ports and the OCS.
- (3) These services generally are carried out by contractors using vessels that are designed and/or modified for a specialized purpose, such as seismographic testing. The contractor may own the vessel, but often leases it from a third party. Depending on their function, the vessels may either stay in the same location for long periods of time or regularly move from location to location. Vessels may be foreign-flagged, and vessel owners and/or operators may be foreign individuals or companies.

B. Section 638 and Associated Treasury Regulations.

- (1) For purposes of applying Chapter 1 of the Code (which includes rules for sourcing income) with respect to mines, oil and gas wells, and other natural deposits, IRC § 638 applies the term “United States” as a geographical reference to include the Outer Continental Shelf.
- (2) Under Treas. Reg. § 1.638-1(c)(1), persons, property, or activities that are engaged in or related to the exploration for, or exploitation of, mines, oil and gas wells, or other natural deposits (collectively known as “IRC § 638 Activities”) need not be physically on, connected, or attached to the seabed or subsoil of the OCS to be deemed within the United States.
- (3) Treas. Reg. § 1.638-1(c)(4) clarifies that persons, property, or activities are within the United States only to the extent they are engaged in IRC § 638 Activities.
- (4) Section 638 Activities are not limited to exploration and exploitation. Instead, the activities must merely be related to the exploration for or exploitation of natural resources in the OCS to be considered IRC § 638 Activities.
- (5) **Note:** In PLR 200823005, foreign-owned and leased vessels were engaged in the removal and repair of underwater oil and natural gas pipelines including the inspection, maintenance, and repair of production platforms and wellheads and the salvage of pipelines and production related equipment. The Ruling

concluded that “Although the services do not constitute the actual drilling of oil and gas wells, such repair and remediation of oil and gas infrastructure are clearly related to the exploitation of natural resources and fall within the ambit of IRC § 638.”

- (6) Treas. Reg. § 1.638-1(d) defines natural deposits and natural resources as nonliving resources to which IRC § 611(a) applies (e.g., the depletion deduction). Natural deposits and natural resources do not include sedentary species, fish, or other animal or plant life.

C. Tax Consequences of the OCS being in the United States.

- (1) Section 638 activities may give rise to U.S. source income.
- (2) Accordingly, a foreign corporation that derives income from IRC § 638 Activities may be taxable in the United States. If the foreign corporation is engaged in a U.S. trade or business and the income is effectively connected with that U.S. trade or business, tax is imposed on that income at graduated rates on a net basis under IRC § 882(a). A foreign corporation that derives such income may file Form W-8ECI with the withholding agent (generally the payor) to avoid withholding on such income.
- (3) If the foreign corporation is not engaged in a U.S. trade or business, it is generally liable for tax on its U.S. source income on a gross basis at a 30 percent rate under IRC §§ 881(a). The tax is generally collected by withholding pursuant to IRC §§ 1441 and 1442. Certain types of income, including capital gains, are generally not subject to tax or withholding.
- (4) If the foreign corporation is a resident of a country with which the United States has a bilateral tax treaty, it may be exempt from tax or withholding, or eligible for a reduced rate of withholding, depending on the provisions of the treaty.
- (5) **Note:** In *Adams Challenge (UK) Ltd. v. Commissioner*, 154 T.C. 37 (2020) Judge Lauber of the Tax Court held that petitioner’s income derived from time chartering a vessel used to support pollution remediation and other IRC § 638 Activities was “effectively connected” with the shipowner’s conduct of a U.S. trade or business and accordingly was subject to tax under the Internal Revenue Code and Article 21 (Offshore Exploration and Exploitation Activities) of the U.S.-U.K. income tax treaty (2001).
- (6) A foreign corporation that is claiming a reduced rate of withholding tax or an exemption from withholding tax under a treaty generally must file a Form W-8BEN-E, Certificate of Status of Beneficial Owner for United States Tax Withholding and Reporting (Entities), with the withholding agent (generally the payor). Where issues arise regarding withholding, refer to the regulations under IRC §§ 883, 1441, and 6114, and consider contacting an International Technical Specialist or an International Examiner.
- (7) A vessel engaged in IRC § 638 Activities does not generally derive income from the international operation of a ship, which is often exempt from tax under a treaty or IRC § 883(a)(1). Examiners should ensure that income characterized

as being derived from international transportation activities is not in fact from IRC § 638 Activities.

- (8) If a foreign entity operating in the OCS is claiming it is exempt from U.S. tax, Examiners should verify the foreign entity's activities and the legal basis for its claim. This might include, for example, reviewing contracts and the types of vessels being used by the foreign entity.
- (9) The following U.S. reporting may be required in connection with IRC § 638 Activities:
 - (10) Form 1120-F, U.S. Income Tax Return of a Foreign Corporation, for foreign corporations engaged in a U.S. trade or business.
 - (11) Form 1042, Annual Withholding Tax Return for U.S. Source Income of Foreign Persons, filed by withholding agents that withhold tax on U.S. source payments to foreign corporations not engaged in a U.S. trade or business.
 - (12) Form 8833, Treaty-Based Return Position Disclosure Under Section 6114 or 7701(b), for foreign corporations claiming either an exemption from, or reduced rate of, tax under the provisions of a treaty.
 - (13) Form 941, Employer's Quarterly Federal Tax Return, for foreign corporations conducting IRC § 638 Activities that are required to withhold employment taxes from remuneration to employees.

D. Withholding.

- (1) As discussed above in Section C.3, Tax Consequences of the OCS, being in the United States, payments to foreign companies for IRC § 638 Activities are generally subject to withholding tax under IRC §§ 1441 and 1442.
- (2) A withholding agent is defined in Treas. Reg. § 1.1441-7(a)(1) as any person, U.S. or foreign, that has the control, receipt, custody, disposal, or payment of an item of income of a foreign person subject to withholding. Residence is not relevant in determining whether a person is a withholding agent. A withholding agent may be an exploration and production company, a project manager, or a contractor.
- (3) A foreign company claiming an exemption from withholding under a treaty must file a Form W-8BEN-E with the withholding agent. Additionally, a foreign company is not subject to withholding if it provides the withholding agent a Form W-8ECI certifying that the income is effectively connected to the foreign company's U.S. trade or business.
- (4) An Examiner should review all Forms W-8 provided to withholding agents. If the withholding exemption being claimed by the foreign company is not consistent with the facts (for example, a foreign company with modified and specialized vessels that claims to be engaged in international transportation), the examiner should consider whether the withholding agent should have instead filed a withholding tax return (Form 1042), and is liable for failing to withhold tax.

E. Treaty Claims.

- (1) Treaty claims must be examined closely given the provisions of U.S. bilateral treaties vary from country to country and some treaties (e.g., Norway) may have special provisions with respect to IRC § 638 activities.
- (2) In particular, there is a wide variation among treaties over how the terms “permanent establishment” and “business profits” are defined.
- (3) To be eligible for a treaty benefit, a foreign corporation must be a resident of the foreign country with which the United States has a treaty, qualify under the Limitation on Benefits (if any) article in the treaty, and meet any additional requirements under the treaty article for which it is claiming the benefit.
- (4) Special attention must be given to a foreign entity’s claim that it is exempt from tax under a treaty because it does not have a permanent establishment. A mine, oil or gas well, quarry, or any other site where natural resources are being extracted will give rise to a permanent establishment if the activity is continuous and of a certain duration. The duration may range from 90 days (e.g., the U.S.-Canada treaty) to 12 months (e.g., the U.S.-Germany treaty). Special treaty provisions apply to income that is attributable to a permanent establishment.
- (5) A foreign company claiming an exemption from, or reduced rate of, U.S. tax under an income tax treaty may be required to attach a Form 8833 to its Form 1120-F setting forth:
 - the treaty position and article it is relying upon for the exemption from, or reduced rate of, U.S. tax;
 - its country of residence; and
 - an estimate of the gross income that is exempt from tax.
 - Failure to disclose a treaty-based return position may result in penalties under IRC § 6712.

F. Other Examination Guidance.

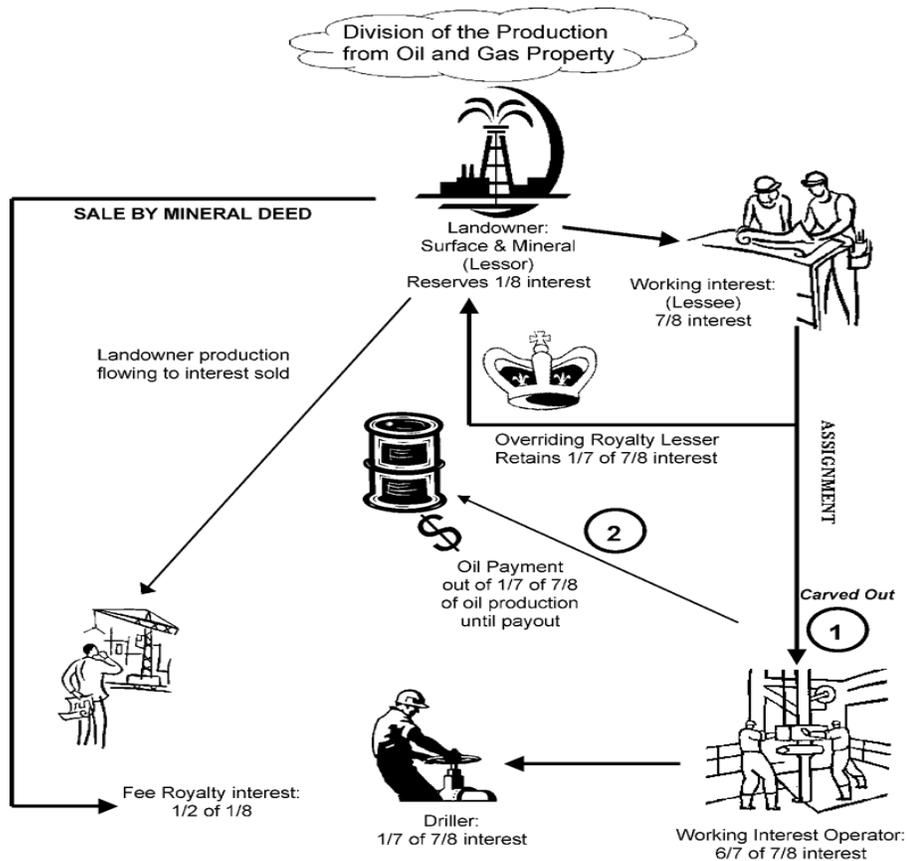
- (1) See Exhibit 34: Employment Tax and the Employees on the U.S. Outer Continental Shelf concerning employment tax issues related to IRC § 638 Activities.

XI. Exhibits

A. Exhibit 1: Research Material Available, Oil and Gas Taxation

- (1) *A Primer of Oilwell Drilling*, PETEX, The University of Texas at Austin
- (2) Bulletins published by the Council of Petroleum Accountants Societies of North America (COPAS)
- (3) *Energy Primer – A Handbook of Energy Market Basics*, Federal Energy Regulatory Commission. URL: <https://www.ferc.gov/sites/default/files/2020-05/energy-primer.pdf>
- (4) *Oil and Gas Journal* (published monthly), PennWell Publishing Co.
- (5) *Manual of Oil and Gas Terms*, 17th Edition, Williams and Meyers
- (6) *How the Oil and Gas Industry Works*, online article by Investopedia. URL is <https://www.investopedia.com/investing/oil-gas-industry-overview/>
- (7) CCH – Oil & Gas Federal Income Taxation (Book for purchase)
- (8) KPMG – Income Taxation of Natural Resources (Book available through Westlaw)

B. Exhibit 2: Division of the Production From Oil and Gas Property



Division of Total Production					
From 1/8 of Production		From 7/8 of Production			
Fee Royalty Interest 1/2 of 1/8	Landowner 1/2 of 1/8	Lessee Override 1/7 of 7/8	Oil Payment 1/7 of 7/8	Driller 1/7 of 7/8	Operator 4/7 of 7/8
No Operating Costs				All Operating Costs	
(1) Pledge for development					
(2) Note: If production payment is sold (not pledged for development), then the operator would report all income with respect to 5/7 of 7/8 interest.					

C. Exhibit 3: Useful Examination Techniques – Lease Acquisition Costs

- (1) Scan the non-producing lease account in the asset section of the ledger to determine the number of oil and gas leases acquired during the year and their names.
- (2) Test lease operating costs, legal and accounting, office supplies, miscellaneous, and similar accounts for acquisition costs that may have been deducted as current expenses.
- (3) Inquire about the taxpayer's method of allocating overhead costs to the leases acquired. Are land department costs, salaries of geological departments, and administrative costs included in the cost of properties acquired? Request copies of authorization for expenditures (AFE) for lease purchases to see if direct costs are set out as part of the cost of the property.

- (4) Test the delay rental account for bonuses that may have been charged to expense in error.
- (5) Has the taxpayer allocated leasehold cost correctly on producing leases purchased? Do you need engineering assistance?
- (6) Determine if geological and geophysical expenditures have been improperly assigned to the basis of acquired leases.
 - See Example 4 in Treas. Reg. § 1.263(a)-2(f)(4) which 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).

D. Exhibit 4: Useful Examination Techniques – Intangible Drilling and Development Costs

- (1) Determine if the taxpayer has made a proper election to deduct IDC as a current expense.
- (2) Test the larger deductions in the IDC expense account.
 - Schedule large amounts;
 - Request invoices;
 - Request AFEs; and,
 - Compare above documents with amounts claimed.
- (3) Inspect the drilling contracts on a selected basis, especially the drilling contracts related to December deductions.
- (4) Determine if prepaid IDC is required by the contract or if it is merely a deposit, and whether or not paid directly to the drilling contractor.
 - Determine when the well was “staked” and when work was started.
 - Consider the facts surrounding the prepaid IDC in relationship to Rev. Rul. 71-579 and Rev. Rul. 71-252.
 - Consider the effect of an adjustment. Does the adjustment have tax significance, or would it be a mere “rollover?” (Remember timing of IDC deduction could affect the net income limit for percentage depletion under IRC § 613A.)

- (5) Scan the depletion schedules to determine which newly acquired leases are productive.
- Have the drilling costs been shown as a deduction on the leases for the 100-percent percentage depletion limitation?
 - Prepare a list of new productive leases from the depletion schedule.
- (6) From the list prepared in item 5 bullet two, request the lease files on all new productive leases, or on a selective basis if the number is large.
- Review the lease files to determine if the taxpayer's ownership percentage corresponds with the amount of IDC deducted. If not, why? Is the deduction allowable?
 - Review assignments, correspondence, and related documents to determine if the taxpayer has drilled for his/her interest in the lease and if he/she is "carrying" other owners.
 - If transactions as described in bullet points 1 and 2 are found, has the taxpayer handled them correctly? See Rev. Rul. 70-657; Rev. Rul. 71-206;; Rev. Rul. 77-176; etc.
- (7) Scan the producing lease account in the asset section of the ledger.
- Note the leases that have been removed (Credits?).
 - Have the leases removed been reported as sales?
 - Should IDC be recaptured in accordance with IRC § 1254?
- (8) Allocate a reasonable amount of administrative overhead costs to IDC for tax preference purposes before computing the minimum tax.
- Usually, this can be done by allocating overhead based upon the direct departmental costs.
 - In many cases, this can be easily accomplished by using the taxpayer's workpapers prepared for the purpose of allocating overhead for depletion purposes.
- (9) Taxpayers must own the entire working interest during the complete payout period to be allowed to deduct 100 percent of the IDC in a carried interest arrangement.
- (10) Has surface casing been deducted?
- (11) Has IDC been shown in operating expenses incorrectly to avoid minimum tax under IRC § 57 or recapture under IRC § 1254?

E. Exhibit 5: Classification of Expenditures in Acquisition, Development, and Operation of Oil and Gas Leases

(1) Leasehold Cost (Capital Expenditure).

- Research of lease location by engineer, geologist, etc.
- Geological and geophysical expenditure incurred after August 8, 2005, leading to acquisition or retention of a foreign oil and gas property. See paragraph 8 of Section II.C.5, Geological and Geophysical Expenditures.
- Expenses in connection with leasing the property from a landowner.
- Legal costs of securing lease and clearing title.
- Legal fees incurred to obtain access to the property and to obtain easements, etc.
- Lease bonus paid to the landowner or other owner.
- Purchase price of an existing lease.
- Core-hole wells drilled to obtain geological data (limited to expenditures after August 8, 2005, for foreign properties. See paragraph 8 of Section II.C.5, Geological and Geophysical Expenditures.
- Cost of seismic work incurred by an oil and gas company to determine the size of the reservoir or reserves (limited to expenditures after August 8, 2005, for foreign properties. See paragraph 8 of Section II.C.5, Geological and Geophysical Expenditures.
- Legal fees incurred in drafting contracts.
- Travel expenses incurred in acquiring leases.
- Salaries of land department personnel in acquiring leases.
- Equalization payments paid in furtherance of a unitization when paid in connection with prior IDC.
- Bottom-hole contribution when paid to obtain information which enhances the value of the property (limited to expenditures after August 8, 2005, for foreign properties; See paragraph 8 of Section II.C.5, Geological and Geophysical Expenditures.
- IDC if no election to expense has been made under IRC § 263(c) or if “foreign IDC.”
- Delay rentals unless the taxpayer can establish that it was not reasonably likely for the lease to be developed.

- Remaining basis in equipment which is transferred to another person under any type of reversionary agreement.

(2) Intangible Drilling Costs (current deductions or capital cost depending on election).

- Administrative costs in connection with drilling contracts.
- Costs of drilling.
- Grading, digging mud pits, and other dirt work to prepare drill site.
- Cost of constructing roads or canals to drill site.
- Surface damage payments to landowner.
- Crop damage payments.
- Costs of setting rig on drill site.
- Transportation costs of moving rig.
- Technical services of geologist, engineer, and others engaged in drilling the well.
- Drilling mud, fluids, and other supplies consumed in drilling the well.
- Transportation of drill pipe and casing.
- Cementing of casing (but not the casing itself).
- Rent of special equipment and tanks to be used in drilling a well.
- Perforating the well casing.
- Logging costs, but not velocity surveys.
- Costs of removing the rig from the location.
- Dirt work in cleaning up the drill site.
- Cost of acidizing, fracturing the formation, and other completion costs.
- Swabbing costs to complete the well.
- Cost of obtaining an operating agreement for drilling operations.
- Cost of plugging the well if it is dry.
- Cost of drill stem tests.

(3) Lease and Well Equipment (Capital Expenditures).

- Surface casing.

- Equalization payments of a unitization when paid in connection with equipment.
- Cost of well casing.
- Saltwater disposal equipment and well.
- Transportation of tubing to supply yard but not from supply yard to well site.
- Cost of production tubing.
- Cost of well head and “Christmas Tree.”
- Cost of pumps and motors including transportation.
- Cost of tanks, flow lines, treaters, separators, etc., including transportation.
- Dirt work for tanks and production equipment.
- Roads constructed for operation of the production phase.
- Laying pipelines, including dirt work and easements.
- Installation costs of tanks and production equipment.
- Construction costs of trucks turnaround pad and overflow pits at new tank battery.

(4) Lease Operating Expense (current deduction).

- Cost of switcher or pumper to operate the wells.
- Cost of minor repair of pumps, tanks, etc.
- Grading existing roads.
- Treat-o-lite and other materials and supplies consumed in operating the lease.
- Pulling sucker rods, pump, and cleaning the well.
- Utilities.
- Taxes other than Federal income taxes.
- Depreciation of equipment used on the lease.
- Rental of lease equipment.
- Salaries for painting and cleaning the lease.
- Lease signs.
- Salaries of other operating personnel--farm boss, superintendent, engineer, etc.

- IDC when elected to expense under IRC § 263(c).
- Saltwater disposal costs (but not equipment listed in paragraph 3 above).
- Allocable portion of overhead costs.
- Qualified tertiary injectant expenses. See Treas. Reg. § 1.193-1 and Section VI.D.6, Other costs.

F. Exhibit 6: Rules Regarding Foreign Geological and Geophysical Expenditures

- (1) Geological and geophysical expenditures incurred in the United States are subject to amortization under IRC § 167(h). However, when foreign geological and geophysical expenditures are encountered, such expenditures are subject to capitalization. The tax treatment of foreign G&G exploration expenditures is governed by other sections of the Code. Rev. Rul. 77-188, 1977-1 C.B. 76, as amplified by Rev. Rul. 83-105, 1983-2 C.B. 51 may also be instructive. These rulings set forth that an exploration program is conducted in stages with specific identification of a project area, area of interest, and the acquisition of properties.
- First, the project area associated with the subject expenditures must be identified. The agent should request copies of the AFEs with respect to expenditures expensed. Generally, taxpayers will incur expenditures regarding reconnaissance type surveys; these are the original or first surveys conducted over a project area. Typically, no specific property (*i.e.*, leasehold) has been acquired at this stage of the project; such reconnaissance type survey costs are held in a suspense account until such time the expenditure may be capitalized to a particular property or an event occurred that enabled the taxpayer to write off such expense.
 - Second, as a result of the reconnaissance type survey, the taxpayer will identify specific geological features that may be conducive for hydrocarbons. Such geological features are defined as an area of interest within the project area. The reconnaissance type survey costs are allocated equally to each area of interest regardless of size or relative costs. The examiner must be aware that taxpayers usually designate many areas of interest so that a large portion of the geological and geophysical costs are capitalized to areas of interest which are abandoned.
 - Lastly, within each area of interest, have specific properties been acquired? If so, the capitalized geological and geophysical expenditures associated with the area of interest (held in

suspense account up to this stage) should be allocated to each property acquired based on acreage.

- (2) If an entire area of interest proves unfavorable for development (i.e., taxpayer decides that the acquisition of acreage or drilling rights is not worthwhile), the allocated exploration costs (e.g., reconnaissance survey costs and detailed survey costs) are deductible as a loss in the year the area is abandoned. See Treas. Reg. § 1.614-6(d). Rev. Rul. 83-105, Situation 1 establishes an identifiable event is a prerequisite for a loss deduction, a decision not to pursue a particular area of interest is not sufficient. Examples of an identifiable event that would trigger a loss deduction include:
- a lease sale occurs and the taxpayer is unsuccessful in acquiring a lease; and,
 - data obtained indicates the absence of mineral producing potential.
- (3) If only a portion of an area of interest proves worthless, a loss cannot be deducted until the complete area of interest is abandoned as a potential source of mineral production. The taxpayer's lease record and the taxpayer's current land map should disclose if the taxpayer holds any leases within the project area.
- **Example:** The *OilCoA*, as a result of a 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 \$10,000 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, *OilCoA* selected 2,500 acres under the lease which they paid \$25,000 bonus. The \$40,000 option cost, the \$24,000 geological and geophysical expenditures, and the \$25,000 bonus should be capitalized as leasehold costs of the 2,500 acres of land selected. 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 "release acreage" when the company never had a lease on the acreage only an option. The lease record usually identifies a lease by its terms, bonus, acreage,

and other provisions, thereby making possible the identification of each lease acquired.

- **Note:** Remember that each geological and geophysical expenditures incurred in an area of interest is 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 whether an option was obtained as a protective measure during the study. See Rev. Rul. 77-188, 1977-1 C.B. 76. For further explanation of Rev. Rul. 77-188 and detailed examples of the tax treatment of foreign geological and geophysical costs, see Rev. Rul. 83-105, 1983-2 C.B. 51.

G. Exhibit 7: Information Required Before Maximum Allowable Depletion Can be Computed

- (1) What is the taxpayer's average daily production of domestic crude oil and how was it computed (IRC § 613A(c)(2))?
- (2) Is the taxpayer required to share the tentative depletable oil quantity with related entities or family members (see IRC §§ 613A(c)(3) and (8))?
- (3) If question 2 is "yes", determine the taxpayer's individual share of tentative oil quantity under IRC §§ 613A(c)(3) and (8).
- (4) Is the percentage depletion limited to 65 percent of adjusted taxable income?
- (5) Are any of the properties marginal oil or gas production properties held by independent producers or royalty owners?
- (6) Have overhead expenses been allocated to the properties for percentage depletion purposes? Is the taxpayer a refiner or retailer (IRC § 613A(d)(2) or (4))?

- Note: The information above is not needed for a taxpayer with only a few small oil and gas leases because the facts may be obvious. However, for a taxpayer with large production, much time can be saved by obtaining the facts above before making any computations.

H. Exhibit 8: Steps in the Computation of Depletion for All Taxpayers Other Than Retailers or Refiners as Defined in IRC § 613A(d)(2) & (4)

- (1) Steps:
 - Start with a schedule of all properties in which the taxpayer owns an economic interest and derives income from the production of oil or gas.

- If the taxpayer is on a tax year different than a calendar year, for computation of percentage depletion under IRC § 613A(c), treat each part of a calendar year within the tax year as if it were a “short period” return.
- Two separate percentage depletion computation schedules are required for a fiscal-year taxpayer. For each property, the allowable percentage depletion deductions from each schedule are combined to compute the property’s allowable percentage depletion deduction for the fiscal year.
- Each property’s allowable percentage depletion deduction is then compared with that property’s cost depletion deduction. The larger of the two computed deductions is the tentative allowable depletion deduction.
- The agent should scan the schedule for leases with similar names and consider the effect on the computations if properties with similar names were, in fact, one property as defined in IRC § 614. The agent should obtain the lease acquisition and well files for the purpose of determining if these wells were drilled on a single property as defined in IRC § 614(a) and if their income and expense should have been reported together on the depletion computation schedule.
- The schedule below illustrates what a depletion schedule might look-like per the tax return. All depletion schedules should show and compute for each property the following:

Oil & Gas Depletion						
Leases	M	N	O	Y	Total	Notes
Gross Income from Property	\$400	\$600	\$334		\$1,334	2a
Direct Operating Expenses	\$200	\$400	\$234	\$200	\$1,034	2b
Intangible Drilling Costs						2c
Allocable Indirect Expenses	\$50	\$100	\$40	-	\$190	2d
Taxable Income from the Property	\$150	\$100	\$60	(\$200)	\$110	2e
Percentage Depletion Computation:						
a. 15% of Gross Income	\$60	\$90	\$50	\$ -	\$200	2f
b. Net Taxable Income	\$150	\$100	\$60	\$ -	\$310	
Lesser of a. or b.	\$60	\$90	\$50	\$ -	\$200	2g
Cost Depletion (From Schedule)	\$40	\$ -	\$10	\$20	\$70	2h
Tentative Depletion - Greater of Percentage or Cost	\$60	\$90	\$50	\$20	\$220	2i

Percentage Depletion	\$60	\$90	\$50	\$ -	\$200	2f
Limited to 65% of Total Taxable Income (Allocated to Property)	\$20	\$29	\$16	\$ -	\$65 *	3
Greater of: Percentage (as Limited) or Cost	\$40	\$29	\$16	\$20	\$105	
Percentage Depletion						
(Remaining Properties Using % Depletion)	\$ -	\$90	\$50	\$ -	\$140	
Limited to 65% of Total Taxable Income (Allocated to Property)	\$ -	\$42	\$23	\$ -	\$65 *	3
Allowable Depletion before Barrel Limitation	\$40	\$42	\$23	\$20	\$125	
**Barrel Limitation on Percentage Depletion	\$ -	\$23	\$13	\$ -	\$36	4
Allowable Depletion after Barrel Limitation	\$40	\$19	\$10	\$20	\$89	
Depletion Carryover:						
Allowable % Depletion BEFORE Considering 65% Taxable Income Limitation	\$60	\$90	\$50	\$ -	\$200	2f
Depletion Allowed for the Properties	\$40	\$42	\$23	\$ -	\$105	
Depletion Carried to Next Year	\$20	\$48	\$27	\$ -	\$95	5
* Taxable Income as Corrected						
** Based on Depletable Oil Quantity (see explanation below)						

(2) **The 65 Percent Taxable Limitation.** Where percentage depletion exceeds cost depletion, the tentative determined above may be limited to 65 percent of the taxpayer's taxable income under IRC § 613A(d)(1). This 65 percent limitation amount is computed by:

- Starting with the taxpayer's taxable income per return.
- Adding back to income: (1) any operating loss carryback (IRC § 172); (2) any capital loss carryback (IRC § 1212); and (3) in the case of most trusts, distributions to the beneficiaries (see IRC § 613A(d)(1)(D)).
- Adding back to income: Any depletion on production from an oil or gas property which is subject on the provisions of IRC § 613A(c) (Exemption for Independent Producers and Royalty Owners).

- In the case of an individual: Subtract the “zero bracket amount.”
 - Make appropriate adjustments to income based on audit recommendations.
- (3) Multiply the results obtained in above by 0.65. This product is the 65 percent of taxpayer’s taxable income limitation amount. The taxpayer is not allowed to claim percentage depletion under IRC § 613A(c) in excess of this amount.
- If the tentative depletion determined above does not exceed the 65 percent limitation amount, the tentative depletion is the allowable depletion for those properties.
 - If the tentative depletion determined above exceeds the 65 percent limitation amount, however, the excess is disallowed and must be allocated to each of the properties so that the allowable percentage depletion can be compared again with the cost depletion applicable to each property (the greater of cost depletion or percentage depletion is the allowable depletion, see IRC §§ 613(a) and 613A(d)(1)).
- (4) **The Barrel Limitation (Depletable Oil Quantity).** Under IRC § 613A(c)(1)(A), the allowed percentage depletion amount is computed with respect to the taxpayer’s average daily production of domestic crude oil that does not exceed the taxpayer’s depletable oil quantity. Section 613A(c)(3)(A) defines “depletable oil quantity” as being 1,000 barrels reduced by the taxpayer’s average daily marginal production for the taxable year. Although the Code defines depletable oil quantity in terms of barrels per day, the agent will be better able to make computations and keep the taxpayer’s depletion under IRC § 613A(c) in perspective if the depletable quantity of oil is expressed in terms of barrels per tax period. Therefore, we have expressed the amount of oil subject to percentage depletion under IRC § 613A(c) in terms of barrels per tax period. Steps to consider in examining the barrel limitation issue include:
- (5) Include “all” production.
 - (6) Reconcile all production on return.
 - (7) Is production from “flow through entities” included?
 - (8) Spot check price per barrel by dividing gross income by barrels per lease or property.
 - (9) If large differences in price per barrel appears between properties, investigate.
 - (10) Business under common control and members of the same family are treated as one taxpayer, and the tentative quantity must be allocated. See IRC § 613A(a)(8).
 - (11) Compute the total of the taxpayer’s production of oil in barrels and gas in barrel equivalents for all properties. If the production from the taxpayer’s properties

exceeds 365,000 barrels (1,000 barrels multiplied by 365 days), then the “depletable oil quantity” will apply.

(12) Oil and gas should not be separated for each property. Separate schedules can be prepared for primary production and marginal production. The taxpayer can allocate the barrel limitation to marginal production first, then to primary production. The schedules should provide the information below:

- Name of the property;
- Whether the property is marginal or not;
- Number of barrels of production for the tax period;
- Convert the gas to barrel equivalents at 1 barrel = 6 MCF of gas; and
- Add barrels of oil to barrels of gas to get the total production from property for the taxable year.
- **Note:** Percentage depletion disallowed per under the Barrel or Depletable Oil Quantity limitation may not be carried over in any prior or subsequent tax year and is lost forever.

(13) **Carryover of Percentage Depletion Disallowed from 65 Percent Limitation.**

IRC 613A(d)(1) provides that any amount of percentage depletion disallowed because of the 65 percent of taxable income limitation will be treated as an amount allowable under IRC § 613A(c) in the following year. In the following year, the amount carried over is again subject to the 65 percent limitation using the same steps outlined above.

(14) The allocation of disallowed depletion should be computed in a schedule which has the following column headings:

- Name of Property
- Cost Depletion
- Tentative Allowable Percentage Depletion
- Disallowed Percentage Depletion

I. Exhibit 9: Allocation of Overhead Expenses

- (1) This exhibit is an example of the proper allocation of a company’s overhead to the various producing leases. The allocation is based on direct expenses. The allocation is required under Treas. Reg. § 1.613-5(a) for the computation of taxable income from the property and the 50 percent of taxable income limitation in computing percentage depletion. See Treas. Reg. § 1.613-1.
- (2) If a taxpayer has not made an allocation of overhead to the various leases, the agent should scan the depletion computation schedules to decide whether an allocation of overhead would probably affect an adjustment in depletion. This

determination is made by examining how near to the 100 percent taxable income limitation is to the statutory 15 percent, or other applicable percent, of gross income. If an adjustment is probable, the agent should scan the unallocated overhead account to determine the proportion that would most likely be allocated to producing leases. If a relatively significant adjustment appears likely, the agent should make the allocation schedule. Computer assistance may be requested in larger cases.

- (3) If the taxpayer has made an overhead allocation, the agent should consider the points listed in (2) above. If adjustment to depletion might be significantly affected by a reallocation, the agent should carefully analyze the taxpayer's overhead allocation and verify that it is based on an acceptable method.
- (4) Interest expense paid on money borrowed for operating capital is an overhead item which should be allocated to producing and nonproducing activities prior to allocation among the properties. Interest expense paid on money borrowed for investment (equipment, IDC, leasehold, etc.) is a direct expense of those properties and should be allocated to them 100 percent.
- (5) If the taxpayer operates their properties in conjunction with properties owned by others and charges a fee for services, the fee is not a credit to the taxpayer's operating expenses or overhead account; it is an income item. However, to the extent that the taxpayer has expenses connected with earning these fees, the expenses should not be charged to his/her leases.
- (6) In examining the allocation, the agent should verify that "nonproducing" activities are consistently treated. If a well was capable of production but was temporarily shut-in (perhaps while awaiting pipeline connection), its expenses should not be included under nonproducing for allocation between producing and nonproducing activities and also included under producing properties in allocating to the various leases.
- (7) Once the allocation is made to specific properties, the agent should verify that the overhead is properly entered in the "line computation" for the property. The agent should be particularly alert for transposition errors between properties with similar names.

J. Exhibit 10: Items To Consider During Examination

- (1) Leases Expired or Forfeited:
 - Obtain list of leases charged off description, etc.
 - Verify cost or basis-expiration date of lease.
 - Review current lease records for evidence of top leasing.
 - Are leases involved in a unitization or other reclassification?
 - Partial abandonments are not deductible.
- (2) Intangible Development Costs (IDC):

- Has a proper election been made? See Treas. Reg. § 1.612-4; IRC §§ 59(e) and 291.
- Are there advance payments involved? See Rev. Rul. 71-252.
- Are tangible costs included? See Treas. Reg. § 1.612-4(a).
- Do IDC costs correspond to taxpayer's interest in property? How was it acquired?
- If the taxpayer is a corporation which is an integrated oil company, did it reduce its IRC § 263(c) deductions (IDC for years after 1982) by 30 percent as required by IRC § 291(b)?

(3) Condemned or Expired Royalties:

- Determine proper year of deduction based on event taxpayer relied on.
- Verify tax basis. Has amount been previously charged off?
- Has taxpayer disposed of the title to the property?

(4) Dry-Hole Costs:

- Is the expense charged to the appropriate property for purpose of computing the depletion limitation?
- Examine contracts; determine existence of dry-hole contributions, bottom-hole contributions, and farm-ins.
- Do dry hole costs include only abandonments? IDC with respect to dry hole costs are deductible under IRC § 263(c) unless the taxpayer has elected to capitalize all of its IDC. See Treas. Reg. § 1.612-4(e).

(5) Depletion:

- Is taxable income (before depletion) computed by property? Percentage depletion cannot exceed 50 percent of the property's taxable income for years beginning prior to 1991. For tax years 1991 through 1997, percentage depletion cannot exceed 100 percent of the property's taxable income. For taxable years beginning after 1997 and before 2008, and tax years beginning after 2008 and before 2012, the net income limitation does not apply to domestic oil and gas production from marginal properties (note: no provision covers tax years beginning after December 31, 2007 and before January 1, 2009).
- Is depletion claimed on proven properties acquired after January 1, 1975?

- Section 613A(d) limits the percentage depletion to 65 percent of the taxpayer's current year taxable income, calculated without considering any percentage depletion deductions.

(6) Gross Income:

- Obtain detailed schedule of lease operations for current and prior year. (Depletion schedules may serve for this purpose.)
- Compare reported receipts, by property, secure explanations for all unusual increases or decreases.
- Test income on run tickets for selected leases and selected months.
- Working interest income is subject to self-employment tax.

(7) Operating Expenses:

- Analyze for large unusual expenses and capital expenditures.
- Legal and professional and geological and geophysical (G&G) expenditures may be incorrectly charged to current expense as "Other Professional Expenses: on Line 26. G&G expenditures are subject to IRC §167(h).
- Determine why some leases have losses.

K. Exhibit 11: Useful Examination Techniques – Oil and Gas Income

(1) Reconcile the oil and gas income on the depletion schedule to the taxpayer's books.

- Review the depletion schedules or the subledgers and list the leases that are operating at a large loss.
- Determine the reasons for the losses.
- If a large loss is not caused by IDC or some unusual expense, request the lease file and oil run tickets.
- From the lease file, determine if the income-sharing arrangement is proper. Income may have been diverted to production payments, selected entities, or children.

(2) Compare the oil run tickets to the oil income reported on a test basis.

(3) Analyze the suspense account for income that should be recognized in the current year.

(4) Verify the accuracy of the oil and gas payout account for joint owners:

- Does a credit balance represent oil and gas income that the taxpayer should report?
 - If all income received by an operator is posted as a credit to the oil and gas payout account, has the operator transferred its share to the income account?
 - Do the debits and credits to the oil and gas payout account balance on a monthly basis? If not, why?
- (5) Test the accuracy of oil and gas income reported on selected leases:
- Compare lease income reported with the oil run tickets for selected months.
 - Reconcile the differences.

L. Exhibit 12: AFRA Computation Method

(1) Average Freight Rate Assessment (AFRA)

Vessel Category	Abbreviation	Vessel dwt (Long Tons)
Medium Range	MR	25,000-44,999
Large Range 1	LR-1	45,000-79,999
Large Range 2	LR-2	80,000-159,999
Very Large Crude Carrier	VLCC	160,000-319,999
Ultra Large Crude Carrier	ULCC	320,000-549,999

(2) The following is an example of how the multi-rate AFRA freight charge is computed for a shipment from Forcados, Nigeria to Philadelphia on a 74,499 dwt (long ton) vessel (75,694 metric ton dwt equivalent) loaded July 4, 1997.

- The vessel size (dwt) determines the AFRA category rate, LR-1 in this example.
- Multirate AFRA for a 75,694 metric ton vessel loaded in July 1997, is W131.3.
- The 1997 Worldscale rate for a voyage from Forcados to Philadelphia is \$7.40 per metric ton.
- The AFRA rate times the Worldscale rate gives the rate per ton (W 131.3 x 7.40 = \$9.69).
- The actual cargo times the rate per ton gives the total charge:

Vessel dwt (LR-1 Category)	75,694	metric tons
Less: Bunker fuel, water, and stores	(4,694)	metric tons
Cargo (actual cargo loaded)	71,000	metric tons
Rate per ton (see 4. above)	\$9.69	per metric ton

Total charge per cargo	\$687,990	

- **Note:** This example does not include the effect of the fixed rate differential applicable in respect of additional premiums for coverage of Oil Pollution Liability Insurance on vessels carrying crude oil trading to the U.S.

M. Exhibit 13: Cargo Sharing – Example

- (1) Vessel 64,499 dwt (LR-1 category) (65,534 metric ton dw. equivalent)
- (2) Voyage: Loading in Puerto la Cruz and Trinidad in July 1997, Discharging in Philadelphia and New York
- (3) Related U.S. Importer paying multi-rate AFRA rates: 30,000 metric ton cargo from Puerto la Cruz to Philadelphia \$4.49 per metric ton
- (4) Third-Party cargo sharing at spot rate per ton: 30,000 metric ton cargo from Trinidad to New York \$6.00 per ton.

	Total	Multiport Rate	Related Importer	Third-Party Importer
Cargo (Metric Tons)	60,000		30,000	30,000
Worldscale Rates		\$5.64	\$4.49	
Multirate AFRA (July 1997)				
For a 65,543 metric ton vessel		W141.2		
For a 30,000 metric ton cargo			W185.9	
Multiport Rate		\$7.96		
Single Discharge Rate			\$8.35	
Third Party Spot Rate				\$7.00
Limitation a.				
Total Cargo 60,000 metric tons X multiport rate (\$7.96)				\$477,600
Less charge paid by third party [30,000 metric tons X spot rate (\$6.00)]				\$210,000
Limitation a. Charge				\$267,600
Limitation b.				
Related Importer cargo 30,000 metric tons X single discharge rate (\$8.35)				\$250,500
Amount allowable:				
The lesser of limitation a. or b.				\$250,000

- This example does not include the effect of the fixed rate differential applicable in respect of additional premiums for

coverage of Oil Pollution Liability Insurance on vessels carrying crude oil trading to the U.S.

N. Exhibit 14: Computation of Dead Freight and Dead Freight Limitation

Worldscale Rate	\$16.40
AFRA Rate LR-1 Category	.783
Cost per Ton	\$12.84

- (1) The barrel cost for cargo based on a fully loaded vessel is computed as follows: Cost per ton \$12.84_7.4917 (barrels per long ton) = \$1.714. The charge for dead freight is not fully allowable because the actual charge per barrel exceeds the charge per barrel that would have been incurred had the cargo been transported in a fully loaded vessel capable of clearing the draft limitations of the loading and discharge ports. The allowable dead freight is computed as follows:

	TOTAL	CARGO	DEAD FREIGHT
Shipment Charge based on Vessel size LR-2	\$770,554	\$516,834	\$253,719
Maximum Allowable:			
Cargo 412,043 barrels x \$1.714 =	706,242	516,835	189,407
Deadfreight Not Allowable	\$64,312	-0-	\$64,312

O. Exhibit 15: Computation of Dead Freight Using Multirate AFRA

- (1) Caution: This section may be revised.
- A vessel of 110,000 dwt moved cargo of 75,000 tons from Bonny Nigeria to the U.S. Gulf Coast. The cargo was loaded in July 1985.

	AFRA Index	WS Rate	Charge per Ton
Actual Vessel of 110,000 dwt	41.7	\$ 14.30	\$ 5.96
Smallest fully loaded vessel that could carry the cargo (75,000 dwt x 103 percent) = 77,250 dwt	57.2	\$ 14.30	\$ 8.18
Computation of the voyage charge including dead freight			
1. Total tons carrying capacity			110,000
Vessel			
dwt			
Less: Bunker			(2,800)
Stores, water, supplies			(350)
Ballast included in dwt			(4,270)
Net carrying capacity			102,580

Dead freight limitation			
(70 percent of 110,000)		77,000	
Less actual cargo		75,000	
Dead freight not allowable	2,000		(2,000)
Cargo and dead freight			100,580
Rate for vessels dwt			x 5.96
Charge based on cargo and dead freight			\$599,467
2. The cargo times the rate for the smallest fully loaded vessel that could carry the cargo			
Total tons loaded			75,000
Assumed vessel gross			77,250
up (103 percent of 75,000)			
Rate per ton for 77,250 dwt vessel			\$8.18
Actual cargo (tons)			x 75,000
Cargo charge for fully loaded vessel			\$613,500
3. Allowable charge			
The lesser of (1) or (2) above			\$599,467

P. Exhibit 16: Analysis of SPE Factual Scenarios of Probable Reserves

- (1) **Scenario #1:** Reserves anticipated to be proved by normal step-out drilling where sub-surface control is inadequate to classify these reserves as proved.
- A well to be drilled as a “normal step-out” is a well to be drilled into an extension of a known deposit. Whether a well is a normal step-out is a question of fact. Proximity to producers is usually indicative of such existence. These types of wells are sometimes referred to as “one location step-outs.” See Rev. Rul. 77-136, 1977-1 CB 167, Exhibit G. The examiner/engineer should include probable reserves associated with normal step-out drilling in the cost depletion computation.
 - Amount of Reserves to include: the quantity most likely to be recovered by the drilling of the normal step-outs. The examiner/engineer may determine the quantity by multiplying the quantity anticipated to be recovered from a successful well by the anticipated probability of success of the well. Taxpayers are likely to maintain estimates of this category of probable reserves.

- The appropriate time to include the estimated quantity is the earlier of:

(1) when the taxpayer classifies the reserves as probable, which may occur as early as the acquisition of the property;

(2) when an authority for expenditure (AFE) to drill the step-out has been approved by the operator;

(3) when an application to drill the step-out well has been approved by the appropriate conservation agency; or

(4) when significant expenditures related to drilling the step-out well have occurred.

(2) **Scenario #2:** Reserves in formations that appear to be productive based on well log characteristic but lack core data or definitive tests and which are not analogous to producing or proved reservoirs in the area.

- The existence of multiple geologic formations is a common occurrence in many geographic locations. Information gathered in the course of drilling and logging wells routinely identifies these “behind pipe” formations. The testing of behind pipe formations is a common part of the complete development of any oil and gas property. The formations are described as not being “analogous to producing or proved reservoirs in the area”, thus they would not be extensions of a known deposit. Whether they represent a new body or mass whose existence is indicated by geological surveys or other evidence to a high degree of probability is a question of fact. The ability to determine the vertical extent and petrophysical properties of these formations is usually evidence of such existence. The fact that the taxpayer describes the reserves contained in the formation as probable is further evidence of such existence. Accordingly, the examiner/engineer should include probable reserves associated with these formations in the cost depletion computation.
- Amount of Reserves to include: the quantity most likely to be recovered by the testing of the behind pipe formations. The examiner/engineer may determine this quantity by multiplying the amount anticipated to be recovered from a successful well completion by the anticipated probability of success of the completion. Taxpayers are likely to maintain estimates of this category of probable reserves.
- For this type of activity, the appropriate time to include the estimated quantity is the earlier of the four sub-bullets described

above in Scenario #1 but substituting “test the behind pipe formation” for “drill the step-out well.”

- (3) **Scenario #3:** Incremental reserves attributable to infill drilling that could have been classified as proved if closer statutory spacing had been approved at the time of the estimate.
- This scenario is similar to SPE Factual Scenario #4 in that, if certain steps are taken, the taxpayer is likely to recover some additional quantity beyond proved reserves from the assured portion of the deposit. This scenario differs in that it contemplates a change in the regulatory environment. The factual scenario does not indicate whether changes to statutory spacing are routinely approved by the appropriate conservation agency. There is some chance, albeit remote, that the taxpayer may never be able to recover the incremental reserves without a change in the statutory spacing. Examiners/engineers should not include these reserves until they have resolved these uncertainties for this type of activity.
 - Amount of Reserves to include: if the examiner/engineer succeeds in resolving the uncertainties, then the incremental reserves attributable to infill drilling quantity should be included in the cost depletion computation. Taxpayers are likely to maintain estimates of this category of probable reserves if they have substantial onshore holdings. Whether a well is an infill well is a question of fact.

(1) Subject to the foregoing, for this type of activity, the appropriate time to include the estimated quantity is the earlier of the four sub-bullets described above in Scenario #1, but substituting “drill the infill well” for “drill the step-out well.”

- (4) **Scenario #4:** Reserves attributable to improved recovery methods that have been established by repeated commercially successful applications when (a) a project or pilot is planned but not in operation and (b) rock, fluid, and reservoir characteristics appear favorable for commercial application.
- In many instances, companies implement improved recovery projects to recover some additional quantity beyond proved reserves from the assured portion of the deposit. The examiner/engineer should include probable reserves associated with these improved recovery projects in the cost depletion calculation
 - Amount of Reserves to include: the quantity most likely to be recovered by the improved recovery project. The examiner/engineer may determine this quantity by multiplying

the quantity expected to be recovered by successful application of the improved recovery method by the probability of success of the project. Taxpayers are likely to maintain estimates of this category of probable reserves.

- Whether a pilot or project is planned is a question of fact. It shall be considered to have occurred at the earlier of the four sub-bullets described above in Scenario #1 but substituting “conduct the project or pilot” for “drill the step-out well.”
- Once the engineer has determined the pilot or project is planned, the probable reserves estimated should be included.

(5) **Scenario #5:** Reserves in an area of the formation that appears to be separated from the proved area by faulting and the geologic interpretation indicates the subject area is structurally higher than the proved area.

- Separate fault blocks within the same geologic formation are common. While a separate fault block can sometimes be technically classified as a separate reservoir, it is not generally considered an entirely different and separate zone from the known producing zone. The type of well described by the SPE is reasonably analogous to an exploratory step-out. These are step-outs to a producing mineral deposit located at a considerable distance from the producing wells. *See generally* Rev. Rul. 77-136, 1977-1 CB 167. Therefore, IRS engineers consider a separate fault block as a “new body or mass” of the existing mineral deposit.
- Whether the existence of a new body or mass is indicated by geological surveys or other evidence to a high degree of probability is a question of fact. The ability to map a separate fault block with enough certainty to plan a well location is usually evidence of such existence. The fact that the taxpayer describes the reserves contained in the fault block as probable is further evidence of such existence. Accordingly, the examiner/engineer should include probable reserves associated with these formations in the cost depletion computation.
- Amount of Reserves to include: the quantity most likely to be recovered by drilling a well into the formation. The examiner/engineer may determine this quantity by multiplying the amount anticipated to be recovered from a successful well completion by the anticipated probability of success of the completion. Taxpayers are likely to maintain estimates of this category of probable reserves.
- For this type of activity, the appropriate time to include the estimated quantity is the earlier of the four sub-bullets described

above in Scenario #1 but substituting “drilling a well into the formation” for “drill the step-out well.”

(6) **Scenario #6:** Reserves attributable to a future workover, treatment, retreatment, change of equipment, or other mechanical procedures, where such procedure has not been proved successful in wells which exhibit similar behavior in analogous reservoirs.

- This is also similar to SPE Factual Scenario #4 dealing with improved recovery methods because the taxpayer will have to take proactive steps and make expenditures to recover the reserves. However, the nature of the expenditure in this case is more closely related to operations than to development activity. If the described procedures are commercially employed in the industry, then the examiner/engineer may include the associated reserves if a reasonably prudent operator would pursue them. Whether these conditions have been met are questions of fact. As a result of these uncertainties, examiners/engineers should only include these probable reserves until after having resolved them.
- Amount of Reserves to include: if the examiner/engineer succeeds in resolving the uncertainties then the quantity most likely to be recovered by the application of the procedure should be included in the cost depletion computation. The examiner/engineer may determine this quantity by multiplying the amount anticipated to be recovered from a successful procedure by the anticipated probability of success of the procedure. Taxpayers do not normally maintain estimates of this category of probable reserves.

(1) For this type of activity, the appropriate time to include the estimated quantity is the earlier of the four sub-bullets described above in Scenario #1, but substituting “conduct the future workover, treatment, retreatment, change of equipment, or other mechanical procedures” for “drill the step-out well.”

(7) **Scenario #7:** Incremental reserves in proved reservoirs where an alternative interpretation of performance or volumetric data indicates more reserves than can be classified as proved.

- This is similar to Scenario #3 because some additional quantity beyond proved reserves may be recovered from the assured portion of the deposit. This scenario differs in that, in some situations, the additional recovery may occur regardless of whether the taxpayer conducts additional development activities. An estimate of proved reserves made early in the life of a reservoir may be conservative since only limited

performance data is available to predict future production levels. The examiner/engineer should include probable reserves associated with these assured deposits.

Q. Exhibit 17: LOGDP IDR No. 1 – Initial Request

- (1) Using Department of the Treasury Internal Revenue Service Information Document Request, Form 4564, make an initial request for documents. The request goes to xxx Drilling Company for the following information and documents; reference tax year ending December 31, 20XX:
 - Detailed general ledger and all detailed subsidiary ledgers (in electronic format).
 - Chart of accounts.
 - eBook and tax trial balance.
 - Year-end journal entries and adjusting journal entries.
 - Financial Statements - Income Statement and Balance Sheet (audited and/or unaudited).
 - Reconciliation of net income per financial statements to net income per books reported on Schedule M-1, Line 1.
 - Copy of tax returns for inspection (prior and subsequent year returns).
 - Partnership Book Capital Account calculations.
 - Partnership Basis calculations.
 - Calculation of adjusted basis in property contributed.
 - Proof of ownership by partnership in property contributed.
 - Tax workpapers (including Schedule M's) used to compute income and expenses reported on the 20XX Form 1065. Include all of the separately stated items reported on Schedule K.
 - Trial Balance and any other financial statement(s) used to compute book and tax income and expenses for the 20XX tax year. Include all of the separately stated items reported on Schedule K.

R. Exhibit 18: LOGDP IDR No. 2 – Partnership Formation

- (1) See following items from Exhibit 17: LOGDP IDR No. 1 (Initial Request)
 - Copy of tax returns for inspection (prior and subsequent year returns).
 - Partnership Book Capital Account calculations.

- Proof of ownership by partnership in property contributed
- (2) **Note:** An Excel, Word or Adobe-formatted response will be acceptable. Delivery media can be a CD.

S. Exhibit 19: LOGDP IDR No. 3 – Other Investments

- (1) Ask the taxpayer to provide a copy of a check, bank draft, wire transfer, or money order used to pay for the **Subscription Note** in xxx **Drilling Company** partnership. If there was more than one transaction, have the taxpayer provide copies of all instruments used. Copies of the front and back of instrument should also be requested. All copies are to be retained in the case file. Attach a copy of the request with information provided.

T. Exhibit 20: LOGDP IDR No. 4 – Capital Accounts

- (1) The taxpayer should be requested to provide a copy of the following:
- IRC § 704(b) capital accounts, including annual adjustments and changes from formation through the most recent tax year.
 - GAAP or other “book” basis capital accounts (if any), including annual adjustments and changes from inception through the most recent tax year.
 - Schedule of all contributions to the partnership, including specific contribution dates, contribution amounts, itemization of contributed property, tax basis of contributed property on contribution date and fair market value of contributed property on contribution date.
 - Schedule of all distributions from the partnership, including specific distribution dates, distribution amounts, itemization of distributed property, tax basis of distributed property on distribution date and fair market value of distributed property on distribution date.
 - Description of any event(s) that led to an inside/outside basis differential, including date of event, agreements implementing the event(s), estimate of differential and how the differential is being allocated by the partnership.
 - **Note:** An Excel, Word or Adobe formatted response will be acceptable. Delivery media can be a CD.

U. Exhibit 21: LOGDP IDR No. 5 – Subscription Note

- (1) The taxpayer should be asked to provide a copy of Additional Collateral for Subscription Note agreement with xxx Drilling Company.

V. Exhibit 22: LOGDP IDR No. 6 – Partner Capital Accounts

- (1) The following information should be requested for each partner:
 - Documentation of distribution payments from the partnership's oil and gas income and interest income to the partners from the initial year of the partnership to date.
 - Include allocation of gross distributions to note(s) principal, note(s) interest, partners, and any other(s).
 - Include the identification of all payees from the partnership's gross distributions from initial year through current date.

W. Exhibit 23: LOGDP IDR No. 7 – Investments in Oil and Gas Wells

- (1) Ask the company to provide any documents that address, discuss, or allude to the selection of investments or properties in any oil and gas well ventures, partnerships, or other investment vehicles. This request covers, but is not limited to, studies, reports, and advice, whether recorded in writing or by means of electronic or other media including email.
- (2) In addition, ask for any documents that refer to, address, discuss or allude to the value assigned to the turnkey drilling contract associated with the oil and gas well venture and to any decisions made with respect to the turnkey driller chosen to do the drilling, whether recorded in writing or by means of electronic or other media including email.
- (3) Finally, provide any information related to any discussions related to the above requests, describing any such discussion, speech, presentation or other oral communication in the following terms: date, author or speaker, subject matter, reason for communication, result of communication, any other participants (by name, address, other contact information), and any follow-up communications.

X. Exhibit 24: LOGDP IDR No. 8 – Intangible Drilling Costs (IDC)

- (1) Request that xxx Drilling Company provide copies of the following:
 - All signed and dated division orders to mineral interests owned by xxx Drilling Company for which IDCs are claimed.
 - Any signed and dated agreements executed between xxx Drilling Company and the xxx Title Holding Corp. or any other similar company involved in the management of any minerals interest of the xxx Drilling Company.
 - All signed and dated title documents of the prospects and mineral interests in wells held in the name of the xxx Title Holding Corporation or any other similar title holding company for the xxx Drilling Company.

- Any signed and dated agreements executed between xxx Drilling Company and xxx Distribution Corporation or any other company that manages or maintains oil and gas production records or makes royalty payments for xxx Drilling Company on a regular basis.
- All signed and dated lease or farm-out agreements executed between xxx Drilling Company and xxx Exploration Company or any other similar drilling or exploration company conducting business in prospects and farm-outs.
- Signed and dated drilling programs prepared by xxx Exploration Company or any turnkey drilling company for any prospects or wells held by xxx Drilling Company.
- Any signed and dated lease and assignment agreements executed between xxx Drilling Company and any turnkey drilling company or any other company.
- Contact names, addresses, and telephone numbers for those representatives of any turnkey drilling company that managed the drilling of wells for xxx Drilling Company.
- Contact names, addresses, and telephone numbers for those representatives of the xxx Title Holding Corp. Or any other title holding company for any mineral interests for the xxx Drilling Company.
- Contact names, addresses, and telephone numbers for those representatives of xxx Exploration Company or any other operating company that conveyed prospects or farm-outs to the xxx Drilling Company.

(2) Request additional documentation:

- Contact names, addresses, and telephone numbers for those representatives of xxx Distribution or any other company that arranged for or managed oil and gas production records and royalty payments for xxx Drilling Company.
- A listing in hardcopy (and in electronic form, if available) of all wells drilled for which IDC was claimed. For each well, the listing should include the IDC dollar (\$) amount which reconciles to the tax return for the tax year in question, well name, API well number, drilling total depth, location (including county, state, field. name, lease name, offshore well block), OCS lease number and drilling permit number issued by the appropriate oil and gas regulatory agency, and current or final status (e.g., producer, dry-hole, etc.). In addition to the above items for each well, the listing should include the following dates: the well spud

date, the date for end of drilling activity, and the date for end of well completion activity, the date well was tested for production or the date well was re-completed and tested for production.

- For each well, provide the listing of the designated operator, the names of the drilling and turnkey contractors, percentage of working interest owned by the partnership (and each partner), and the date at which the partnership (and each partner) received the working interest in the well.
- Signed and dated copy of the drilling permit obtained from the state or federal agency for each well for which IDC's or dry-hole cost was claimed.
- Signed and dated copy of the subsequent well completion report from the state or federal agency for each well for which IDCs or dry-hole cost was claimed.
- Copy of the signed and dated subsequent plugging and abandonment report from the state or federal agency for each well for which IDC's or dry-hole cost was claimed.
- Pertinent tax work papers reconciling the IDC dollar (\$) amounts for each well identified above and reported on the tax return for the year in question.
- For each well, copy of the ledger account(s) in which the amounts of IDC's were recorded, and a breakdown of the components of the IDC dollar (\$) amounts that reconcile to the claims for IDC amounts.

Y. Exhibit 25: LOGDP IDR No. 9 – Turnkey Driller IDC

(1) Request from xxx Drilling Company answers to these questions:

- Did any IDC costs represent prepaid expenses pursuant to a contractual arrangement? If yes, please identify all wells associated with such IDC costs and provide a copy of such contract.
- Did the Turnkey Driller actually drill the well? If no, please provide the name of the drilling contractor that the operator used to actually drill the wells and the rig used to drill the well.
- Did the Turnkey driller cause the well to be drilled by another party? If yes, please provide the contract between the Turnkey driller and the third party.
- Does the Turnkey Driller actually own drilling rigs and maintain drilling crews? If yes, please identify the rig used, type, depth

rating, and number of employees working for the turnkey drilling contractor.

- Is the Turnkey Driller actively engaged in the drilling business? If yes, please identify the commercial publication listing him as a drilling contractor in the oil and gas industry.
- Were any IDC for dry-hole costs associated with a partial abandonment of a well or non-productive section of a well (e.g., shallow section of well is producing and deduction taken for deeper non-productive portion or side track).

Z. Exhibit 26: Tax Shelter Partner Listing

PARTNER NAME	TOTAL P/S PER PARTNER	Statute Date	XYZ DRILLING COMPANY	ABC DRILLING COMPANY	XXX DRILLING COMPANY	ZZZ DRILLING COMPANY	123 DRILLING COMPANY	AAA DRILLING COMPANY	NEW DRILLING COMPANY
TOTAL PARTNERS PER P/S			3	3	6	6	4	5	5
Partner 1	2	12/31/20xx	1		1				
Partner 2	2	12/31/20xx	1					1	
Partner 3	2	12/31/20xx	1					1	
Partner X	2	12/31/20xx		1		1			
Partner Y	1	12/31/20xx		1					
Partner Z	2	12/31/20xx		1					1
Partner AA	1	12/31/20xx			1				
Partner AB	1	12/31/20xx			1				
Partner AC	2	12/31/20xx			1			1	
Partner 4	2	12/31/20xx				1		1	
Partner 5	1	12/31/20xx				1			
Partner 6	1	12/31/20xx				1			
Partner AAA	1	12/31/20xx				1			
Partner AAB	1	12/31/20xx				1			

Partner AAC	1	12/31/20xx					1		
Partner 7	1	12/31/20xx					1		
Partner 8	2	12/31/20xx			1		1		
Partner 9	3	12/31/20xx			1		1		
Partner ABC	1	12/31/20xx							1
Partner 10	1	12/31/20xx							1
Partner 11	1	12/31/20xx							1
Partner 12	1	12/31/20xx							1

AA. Exhibit 27: MACRS Asset Classes Commonly Used in the Petroleum Industry

Asset Class	Description of Assets Included	Class Life (in years)	Recovery Period (in years)	
			General Depreciation System - IRC § 168(a)	Alternative Depreciation System - IRC § 168(g)
00.3	Land Improvements: Includes improvements directly to or added to land, whether such improvements are IRC § 1245 property or IRC § 1250 property, provided such improvements are depreciable. Examples of such assets might include sidewalks, roads, canals, waterways, drainage facilities, sewers (not including municipal sewers in Class 51), wharves and docks, bridges, fences, landscaping, shrubbery, or radio and television transmitting towers. Does not include land improvements that are explicitly included in any other class, and buildings and structural components as defined in IRC § 1.48-1(e) of the regulations. Excludes public utility initial clearing and grading land improvements as specified in Rev. Rul. 72-403, 1972-2 C.B. 102.	20	15	20

13.0	Offshore Drilling: Includes assets used in offshore drilling for oil and gas such as floating, self-propelled and other drilling vessels, barges, platforms, and drilling equipment and support vessels such as tenders, barges, towboats and crew-boats. Excludes oil and gas production assets.	7.5	5	7.5
13.1	Drilling of Oil and Gas Wells: Includes assets used in the drilling of onshore oil and gas wells and the provision of geophysical and other exploration services; and the provision of such oil and gas field services as chemical treatment, plugging and abandoning of wells and cementing or perforating well casings. Does not include assets used in the performance of any of these activities and services by integrated petroleum and natural gas producers for their own account.	6	5	6
13.2	Exploration for and Production of Petroleum and Natural Gas Deposits: Includes assets used by petroleum and natural gas producers for drilling of wells and production of petroleum and natural gas, including gathering pipelines and related storage facilities. Also includes petroleum and natural gas offshore transportation facilities used by producers and others consisting of platforms (other than drilling platforms classified in Class 13.0), compression or pumping equipment, and gathering and transmission lines to the first onshore transshipment facility. The assets used in the first onshore transshipment facility are also included and consist of separation equipment (used for separation of natural gas, liquids, and solids), compression or pumping equipment (other than equipment classified in Class 49.23), and liquid holding or storage facilities (other than those classified in Class 49.25). Does not include support vessels.	14	7	14
13.3	Petroleum Refining: Includes assets used for the distillation, fractionation, and catalytic cracking of crude petroleum into gasoline and its other	16	10	16

	components.			
15.0	Construction: Includes assets used in construction by general building, special trade, heavy and marine construction contractors, operative and investment builders, real estate sub-dividers and developers, and others except railroads.	6	5	5
28.0	Manufacture of Chemicals and Allied Products: Includes assets used to manufacture basic organic and inorganic chemicals; chemical products to be used in further manufacture, such as synthetic fibers and plastics materials; and finished chemical products. Includes assets used to further process man-made fibers, to manufacture plastic film, and to manufacture nonwoven fabrics, when such assets are located in the same plant in an integrated operation with chemical products producing assets. Also includes assets used to manufacture photographic supplies, such as film, photographic paper, sensitized photographic paper, and developing chemicals. Includes all land improvements associated with plant site or production processes, such as effluent ponds and canals, provided such land improvements are depreciable but does not include buildings and structural components as defined in Treas. Reg. § 1.48- 1(e). Does not include assets used in the manufacture of finished rubber and plastic products or in the production of natural gas products, butane, propane, and byproducts of natural gas production plants.	9.5	5	9.5

46.0	Pipeline Transportation: Includes assets used in the private, commercial, and contract carrying of petroleum, gas and other products by means of pipes and conveyors. The trunk lines and related storage facilities of integrated petroleum and natural gas producers are included in this class. Excludes initial clearing and grading land improvements as specified in Rev. Rul. 72-403, 1972-2 C.B. 102, but includes all other related land improvements.	22	15	22
49.21	Gas Utility Distribution Facilities: Includes gas water heaters and gas conversion equipment installed by utility on customers premises on a rental basis.	35	20	35
49.221	Gas Utility Manufactured Gas Production Plants: Includes assets used in the manufacture of gas having chemical and/or physical properties which do not permit complete interchangeability with domestic natural gas. Does not include gas producing systems and related systems used in waste reduction and resource recovery plants which are elsewhere classified.	30	20	30
49.222	Gas Utility Substitute Natural Gas (SNG) Production Plant (naphtha or lighter hydrocarbon feedstocks): Includes assets used in the catalytic conversion of feed- stocks or naphtha or lighter hydrocarbons to a gaseous fuel which is completely interchangeable with domestic natural gas.	14	7	14
49.23	Natural Gas Production Plant.	14	7	14
49.24	Gas Utility Trunk Pipelines and Related Storage Facilities: Excluding initial clearing and grading land improvements as specified in Rev. Rul. 72-403.	22	5	22
49.25	Liquefied Natural Gas Plant: Includes assets used in the liquefaction, storage, and regasification of natural gas including loading and unloading connections, instrumentation equipment and controls, pumps, vaporizers and odorizers, tanks, and related land improvements. Also includes pipeline interconnections with gas transmission	22	15	22

	lines and distribution systems and marine terminal facilities.			
57.0	Distributive Trades and Services: Includes assets used in wholesale and retail trade, and personal and professional services. Includes IRC § 1245 assets used in marketing petroleum and petroleum products.	9	5	9
57.1	Distributive Trades and Services Billboard, Service Station Buildings and Petroleum Marketing Land Improvements: Includes IRC § 1250 assets, including service station buildings and depreciable land improvements, whether IRC § 1245 property or IRC § 1250 property, used in the marketing of petroleum and petroleum products, but not including any of these facilities related to petroleum and natural gas trunk pipelines. Includes car wash buildings and related land improvements. Includes billboards, whether such assets are IRC § 1245 property or IRC § 1250 property. Excludes all other land improvements, buildings and structural components as defined in Treas. Reg. § 1.48-1(e).	20	15	20
	Per IRC § 168(e)(3)(C) 7- year property includes - (iv) any natural gas gathering line the original use of which commences with the taxpayer after April 11, 2005.	14	7	14
	IRC § 168(e)(3)(E) 15-year property includes - (iii) a retail motor fuels outlet (whether or not food or other convenience items are sold at the outlet). See Rev. Rul. 97-29 or Pub 946 for the applicable definition of “retail motor fuels outlet”.	20	15	20

BB. Exhibit 28: Definitions Related to Oil and Gas Reserves in SEC Regulation S-X Prior to 2010

- (1) Certain definitions related to oil and gas reserves are contained in Regulation S-X (17 C.F.R. § 210.4-10) for filings with the Securities and Exchange Commission (SEC) prior to 2010.
- (2) *Proved oil and gas reserves.* Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in

future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

- Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes a) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and b) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.
 - Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the “proved” classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.
 - Estimates of proved reserves do not include the following: a) oil that may become available from known reservoirs but is classified separately as “indicated additional reserves”; b) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; c) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and d) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.
- (3) *Proved developed oil and gas reserves.* Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as “proved developed reserves” only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.
- (4) *Proved undeveloped reserves.* Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage is limited to those drilling units

offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

CC. Exhibit 29: Definitions Related to Oil and Gas Reserves in SEC Regulation S-X After 2009

- (1) Certain definitions related to oil and gas reserves are contained in Regulation S-X (17 C.F.R. § 210.4-10) for filings with the Securities and Exchange Commission (SEC) after 2009.
- (2) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.
- (3) The area of the reservoir considered as proved includes:
 - The area identified by drilling and limited by fluid contacts, if any, and
 - Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.
- (4) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.
- (5) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

- (6) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:
- Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and
 - The project has been approved for development by all necessary parties and entities, including governmental entities.
- (7) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price is the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.
- (8) *Probable reserves*. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.
- (9) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50 percent probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.
- (10) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.
- (11) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.
- (12) *Reasonable certainty*. If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience

(geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

DD. Exhibit 30: Rev. Proc. 2004-19 and the Elective Safe Harbor for Determining a Property's Recoverable Reserves for Purposes of Computing Cost Depletion

(1) Introduction

- This exhibit provides direction for the effective use of audit time and resources devoted to the examination of oil and gas taxpayers claiming cost depletion deductions for oil and gas properties. This exhibit is not an official pronouncement of the law or the position of the Service and cannot be used, cited, or relied upon as such.

(2) Background

- For purposes of computing cost depletion, taxpayers are required to include all recoverable units of mineral in the total number of recoverable units at the end of the year. Recoverable units include both proved reserves (developed and undeveloped) and, under appropriate circumstances, additional reserves. See section VII.C.2 - Reserves of Oil and Gas.
- The appropriate quantity of probable or prospective reserves to be included in an oil and gas property's total recoverable units for purposes of computing cost depletion has been a source of controversy between taxpayers and the Service. When present, the issue has been resolved through examinations that are costly for both parties in the dispute. Rev. Proc. 2004-19, 2004-10 I.R.B. 563, provides an elective safe harbor that is intended to remove this source of controversy from the examinations of those taxpayers who elect it.

(3) Revenue Procedure 2004-19

- Under Rev. Proc. 2004-19, taxpayers may elect a safe harbor to determine the total recoverable reserves for its oil and gas properties. The elective safe harbor applies to all of the electing taxpayer's domestic oil and gas producing properties. If a taxpayer elects the safe harbor provided by section 5 of Rev. Proc. 2004-19, then, for purposes of computing cost depletion: (1) the total recoverable units under Treas. Reg. § 1.611-2(c)(1) that each of the taxpayer's domestic oil and gas producing properties is estimated to contain as of a specific date will be treated as equal to 105 percent of the property's "proved

reserves” (both developed and undeveloped) as defined in 17 C.F.R. § 210.4-10(a) of Regulation S-X, as of that date and (2) the total recoverable units under Treas. Reg. § 1.611-2(c)(2) that each of the taxpayer’s domestic oil and gas producing properties is estimated, on a revised basis, to contain as of a specific date will be treated as equal to 105 percent of the property’s “proved reserves” (both developed and undeveloped) as defined in 17 C.F.R. § 210.4-10(a) of Regulation S-X, as of that date.

- An election of the safe harbor provided by Rev. Proc. 2004-19 applies to taxable years ending on or after March 8, 2004, unless the election is revoked under the procedures contained in section 5.01(2) of Rev. Proc. 2004-19.
- If the first taxable year for which a taxpayer elects the safe harbor begins before January 1, 2005, the taxpayer may, for the taxable year of election, use economic conditions to revise the estimate of recoverable reserves whether or not there has been a change in geological fact.
- If the first taxable year for which a taxpayer elects the safe harbor begins after December 31, 2004, the taxpayer may not revise the estimate of remaining recoverable units unless there has been a change in geological fact. The use of economic conditions to revise the estimate of recoverable reserves is only available for the one taxable year beginning before January 1, 2005. See sections 5.02 and 5.03 of Rev. Proc 2004-19.
- Nothing in Rev. Proc. 2004-19 precludes the examination and adjustment, if appropriate, of the estimate of “proved reserves” as defined in § 210.4-10(a) of Regulation S-X in order to ensure that the safe harbor provided by Rev. Proc. 2004-19 is properly administered. Further, except as provided in section 5.02 of Rev. Proc. 2004-19, a taxpayer’s estimate of a property’s remaining recoverable units may be revised only under the circumstances permitted under Treas. Reg. § 1.611-2(c)(2).

(4) Recommendation

- When a taxpayer does not elect to use the safe harbor provided in Rev. Proc. 2004-19 for all of its domestic oil and gas properties, examiners should refer to section VII.C.2 - Reserves of Oil and Gas.
- If there are any questions relating to this matter, please contact the Petroleum Industry Specialist or the Deductible and Capital Expenditures Practice Network.

(5) Examples

- The following examples demonstrate the application of the procedures described Rev. Proc. 2004-19 in a variety of circumstances that examiners are likely to see. For purposes of these examples “book reserves” or “book purposes” refers to proved reserves (both developed and undeveloped) as defined in 17 C.F.R. § 210.4-10(a) of Regulation S-X.

(6) Situation 1:

- For a tax year ending on or after March 8, 2004, and beginning before January 1, 2005, a taxpayer elects to use the provisions of the safe harbor for all of its domestic oil and gas properties.
- **Property A:** At the start of the year, remaining proved reserves per books are 110 units. During the year 10 units are produced and sold. There was no indication from operational or development work during the year to indicate that the beginning-of-year estimate required a material change, nor did the taxpayer revise the estimate for any other reason. Proved reserves at year end for book purposes are 100 units as follows:

Beginning-of-year	110 units
Revisions during year	0 units
Amount produced and sold	-10 units
End-of-year	100 units

- For purposes of computing the cost depletion deduction, the end-of-year recoverable units are 105 units (100 units of book proved reserves multiplied by 105%).
- **Property B:** At the start of the year remaining proved reserves are 110 units. During the year 10 units are produced and sold. There was no indication from operational or development work during the year to indicate that the beginning-of-year estimate required a material change. However, during the taxable year there was a negative change in economic conditions and accordingly the taxpayer made a downward revision of proved reserves for book purposes of 15 units. Proved reserves at year end for book purposes are 85 units as follows:

Beginning-of-year	110 units
Revisions during year due to operations and development	0 units

work	
Revisions during year not due to operations and development work	-15 units
Amount produced and sold	-10 units
End-of-year	85 units

- Because of the provision of Section 5.02 of the revenue procedure (Election of Safe Harbor for Taxable Year Beginning Before January 1, 2005), the revision due solely to a change in economic conditions is permissible. For purposes of computing the cost depletion deduction, the end-of-year recoverable units are 89.25 units (85 units of book proved reserves multiplied by 105%). Similar results would occur had the revision occurred prior to the beginning of the year and been reflected in the beginning-of-year proved reserves for book purposes. That is, year-end tax reserves would equal year-end book reserves multiplied by 105%.

(7) Situation 2:

- Assume that the taxpayer and properties described in Situation 1 remain the same for the subsequent tax year (which begins after December 31, 2004) and the taxpayer does not revoke its election to use the provisions of the revenue procedure.
- **Property A:** At the start of the year the remaining proved reserves for book purposes are 100 units. During the year 10 units are produced and sold. There was no revision based on operational or development work during the year and no revision for any other reason. Thus, the taxpayer's estimate of proved reserves at year end for book purposes is 90 units (100 units at beginning-of-year less 10 units produced and sold).
- For purposes of computing the cost depletion deduction, the end-of-year recoverable units are 95 units (105 units of tax reserves remaining as of the beginning of the year minus 10 units produced and sold during the taxable year).
- **Property B:** At the start of the year the remaining proved reserves for book purposes are 85 units. During the year 10 units are produced and sold. There was no revision based on operational or development work during the year. However, during the taxable year there was a negative change in economic conditions and taxpayer made another downward revision of proved reserves for book purposes of 15 units.

Proved reserves at year end for book purposes are 60 units as follows:

Beginning-of-year	85 units
Revisions during year due to operations and development work	0 units
Revisions during year not due to operations and development work	-15 units
Amount produced and sold	-10 units
End-of-year	60 units

- The provision of Section 5.02 of the revenue procedure (Election of Safe Harbor for Taxable Year Beginning Before January 1, 2005) does not apply because this tax year began after December 31, 2004. The revision due solely to a change in economic conditions is not permissible for determining recoverable units for computing cost depletion.
- For purposes of computing the cost depletion deduction, the end-of-year recoverable units are 79.25 units (89.25 units of tax reserves remaining as of the beginning of the year minus 10 units produced and sold during the taxable year).

(8) Situation 3:

- Assume that the taxpayer and properties described in Situations 1 and 2 remain the same for the subsequent tax year (which begins after December 31, 2004) and the taxpayer does not revoke its election to use the provisions of the revenue procedure.
- **Property A:** At the start of the year the remaining proved reserves for book purposes are 90 units. During the year another 10 units are produced and sold. During the year operational or development work indicate that the proved reserves are materially greater than the previous estimate, and the taxpayer made an upward revision of 30 units. The taxpayer did not make any other revision to the estimate during the year. Proved reserves at year end for book purposes are 110 units as follows:

Beginning-of-year	90 units
Revisions during year due to operations and development	30 units

work	
Amount produced and sold	-10 units
End-of-year	110 units

- For purposes of computing the cost depletion deduction, the end-of-year recoverable units are 115.5 units (110 units of year-end book proved reserves multiplied by 105%).
- **Property B:** At the start of the year the remaining proved reserves for book purposes are 60 units. During the year 10 units are produced and sold. During the year operational or development work indicate that the proved reserves are materially less than the previous estimate, and the taxpayer made a downward revision of 20 units. There was also a positive change in economic conditions and accordingly the taxpayer made an upward revision of proved reserves for book purposes of 5 units. Proved reserves at year end for book purposes are 35 units as follows:

Beginning-of-year	60 units
Revisions during year due to operations and development work	-20 units
Revisions during year not due to operations and development work	5 units
Amount produced and sold	-10 units
End-of-year	35 units

- When recoverable units are properly revised due to operations and development work the new estimate should reflect all the conditions as of that time. For purposes of computing the cost depletion deduction, the end-of-year recoverable units are 36.75 units (35 units of year-end book proved reserves multiplied by 105%).

(9) Situation 4:

- For tax year 2006 (which begins after December 31, 2004), a taxpayer first elects to use the provisions of the safe harbor for all of its domestic oil and gas properties.
- **Property C:** At the start of year 2006 the remaining book proved reserves are 200 units determined as follows:

Latest estimate based on operations and development work (year-end 2003)	300 units
Amount produced and sold during 2004:	-30 units
Revisions during 2005 not due to operations and development work	-40 units
Amount produced and sold during 2005	-30 units
Remaining book proved reserves	200 units

- During tax year 2006, 30 units are produced and sold. There was no revision based on operational or development work during the year and no revision for any other reason. Proved reserves at the end of 2006 for book purposes are 170 units as follows:

Beginning-of-year 2006	200 units
Revisions during year due to operations and development work	0 units
Revisions during year not due to operations and development work	0 units
Amount produced and sold	-30 units
End-of-year 2006	170 units

- Because of the provision of Section 5.03 of the revenue procedure (Election of Safe Harbor for Taxable Year Beginning After December 31, 2004), the revision that occurred in 2005 that was not due to operations and development work cannot be reflected in the recoverable units used for computing cost depletion. For purposes of computing the cost depletion deduction, the end-of-year recoverable units are 220.50 units (300 units from the most recent estimate based upon operations and development work minus the 90 units produced and sold in 2004, 2005, and 2006, then multiplied by 105%).

EE. Exhibit 31: Guidance to LB&I Examiners When an LB&I Taxpayer Files an Amended Return or Claim for Refund Related to the Repeal of IRC § 199

(1) Introduction.

- Large Business and International (LB&I) announced a campaign to evaluate claims filed for additional DPAD under IRC § 199 to address compliance risk associated with the repeal of the DPAD.
- This Exhibit 32 provides LB&I examiners with guidance when a taxpayer files an amended return or claim for refund relating to IRC § 199, DPAD. This Exhibit only applies to LB&I taxpayers and is intended to provide a uniform approach to evaluating the claims and ensure the most efficient use of LB&I resources. This Exhibit is not an official pronouncement of the law and cannot be used, cited, or relied upon as such.

(2) Applicable Law.

- Public Law 115-97 (as amended by the Consolidated Appropriations Act, 2018, Public Law 115-141, § 101(c), 132 Stat. 348, 1151, 1156) repealed the DPAD for taxable years beginning after December 31, 2017. Taxpayers should not claim the DPAD for 2018 or later years, unless any of the following applies:
 - the individual's taxable year began before January 1, 2018;
 - the DPAD results from being a shareholder or partner in an S Corporation or partnership with a taxable year that began before January 1, 2018;
 - the DPAD results from being a beneficiary of an estate or trust with a taxable year that began before January 1, 2018; or
 - the DPAD results from being a patron of an agricultural or horticultural cooperative with a taxable year that began before January 1, 2018.
- Prior to its repeal, IRC § 199 generally provided for a tax deduction equal to 9% of the lesser of the taxpayer's QPAI or taxable income for the taxable year. Additionally, the amount of the deduction allowable for any taxable year was limited to 50% of the W-2 wages of the taxpayer for the taxable year properly allocable in the determination of QPAI.

(3) Handling Amended Returns/Refund Claims Under IRC § 199.

- As announced in the IRC § 199 - Claims Risk Review Campaign, LB&I established a process to risk assess IRC § 199 amended returns and claims for refund for taxable years prior to the repeal of IRC § 199. Claims for refund filed with the Ogden Campus or with an examiner will be risk assessed. Materiality will be considered during the risk review process.

- An examiner who receives an informal claim for refund, amended return not filed with the campus, or a Joint Committee case under IRC § 199 is required to submit an inquiry to the Corporate Income and Losses (CIL) Practice Network (PN) via the CIL PN SharePoint site. A member(s) of the risk review team (comprised of CIL PN employees and field examiners) will assist in risk assessing the amended return or claim for refund.
- Examiners will continue to follow the rules and procedures in Publication 5125, LB&I Examination Process, including the expectations with respect to claims for refund. Examiners should also follow IRM 4.46.3.6 with respect to claims and ensure that the claim is valid and meets the requirements of Treas. Reg. § 301.6402-2. The CIL PN is available to assist with this determination.
- When disallowing a claim, in part or in full, examiners will refer to the procedures in IRM 4.10.8.10 and the LB&I Reference Guide for Claims. The Written Acknowledgment of the Facts process in IRM 4.46.4.10 also must be followed.

(4) IRC § 6676 - Penalty Issues.

- IRC § 6676, Erroneous Claim for Refund or Credit, should be considered when appropriate, based on the facts and circumstances of the issue. An examiner may obtain assistance from counsel in determining whether referrals to the Office of Professional Responsibility (OPR) are appropriate.

(5) Exhibit 32: IRC § 907 – Evaluating Taxpayer Methods of Determining Foreign Oil and Gas Extraction Income (FOGEI) and Foreign Oil Related Income (FORI)

(1) Introduction.

- This Exhibit is intended to provide direction to effectively utilize resources in evaluating taxpayer methods of determining under IRC § 907 foreign oil and gas extraction income (FOGEI) and foreign oil related income (FORI). This Exhibit is not an official pronouncement of the law or the Service's position and cannot be used, cited, or relied upon as such.

(2) Background.

- IRC § 907 was enacted in 1975 and final regulations, effective for taxable years beginning after December 31, 1982, were issued in 1991. The Code section limits the creditable foreign taxes assessed on FOGEI to the maximum US tax rate. The basic premise of the statute is to prevent excess foreign tax credits, available because of the very high taxes imposed on

FOGEI by producing countries, from offsetting US tax on other foreign source income. The Code section also limits, in more restricted situations, the creditability of foreign taxes imposed on FORI, which encompasses activities downstream from the well, including transportation of the crude oil and gas from the well to the place of sale and processing of the oil and gas.

- FOGEI is defined in the Code and regulations as taxable income derived from the extraction of minerals from oil or gas wells based on the fair market value (FMV) of the minerals in the immediate vicinity of the well. The regulations under IRC § 907 do not provide specific methods for determining FMV in the immediate vicinity of the well but provide that all the facts and circumstances that exist in the particular case must be considered. The purpose of the flexible fair market value provision is to allow the oil and gas extractor to split the income from the sale of foreign produced minerals between FOGEI and FORI in a reasonable manner.
- While similar fact patterns should produce similar results, since determination of FOGEI (and FORI) is highly factual, there has been little consistency in either the determination of FOGEI by the industry or in examinations by the IRS of the taxpayers' determination. In order to improve consistency and reduce the administrative burden on both taxpayers and the IRS, this Exhibit provides guidance to international examiners (IEs) and specialists on the application of the most two commonly used methods for determining FOGEI (and FORI) when there is no ascertainable market price for the oil and gas in the immediate vicinity of the well.

(3) Discussion.

(4) Methods for Determining FMV in the Immediate Vicinity of the Well.

- Most taxpayers use either a residual (rate of return) method or a proportionate profits method to determine FOGEI. Both of those methods, as well as other methods, are acceptable when applied reasonably and in a manner consistent with the regulations. For example, when comparable costs of transportation or processing are available, taxpayers and IEs may be able to estimate the value of FOGEI through netback adjustments to the sales price of the oil or gas. However, this Exhibit focuses on issues related to the more commonly used residual (or rate of return) method and the proportionate profits method.

(5) Residual (Rate of Return) Method.

- FOGEI is determined under the residual (rate of return) method by first calculating FORI and subtracting FORI from the total income from the production and sale of the oil or gas product. A taxpayer determines FORI by applying an assumed after-tax rate of return to the cost of its fixed FORI assets. Because income from the production and sale of oil and gas product is equal to the sum of FOGEI and FORI, once the total income and FORI are established, FOGEI can then be determined by subtracting FORI from total income. To apply this method, taxpayers and IEs must:
 - Identify which assets are used in FORI activities;
 - Identify the cost of the assets used in FORI activities;
 - Determine appropriate rates of return for FORI assets;
 - Determine total income from the production and sale of the oil and gas product; and
 - Separately identify FOGEI assets and determine the cost of FOGEI assets to test the FORI determination.
 - In most cases, IEs should request a petroleum engineer to evaluate a taxpayer's classification of assets, rate of return assumptions, and calculations. In some cases, an economist may be needed to assist. In all cases, the IE should estimate the tax effect of potential changes before expanding the examination time to permit consultation with engineers and economists. The International Foreign Tax Credit Technical Advisor and the Petroleum Industry Program (PIP) will gather industry data to advise on reasonable rates of return so as to further conserve examination resources.

(6) Proportionate Profits Method.

- FOGEI is determined under the proportionate profits method by allocating total income from the production and sale of the oil or gas product between FOGEI and FORI based on the relative costs of the FOGEI and FORI activities. The proportionate profits method is similar in concept to the proportionate profits method used in Treas. Reg. §1.613-4(d)(4) to determine gross income from mining of hard minerals for purposes of determining allowable percentage depletion. There the formula is:
 - $\text{mining costs}/\text{total costs} \times \text{gross sales} = \text{gross income from mining}$

- non-mining costs/total costs x gross sales = gross income from non-mining
- The regulations under section 613 require that gross sales represent the sales of the first marketable product and that such sales must be reasonable and representative. Calculations are based on net historic cost. The rate of return is not applicable. These concepts apply as well to the FOGEI determination. However, just as with the residual (or rate of return) method examiners must distinguish which costs are classified as FOGEI and which are classified as FORI. This is necessary since FOGEI would be determined under these formulas by substituting FOGEI costs in the numerator of the first formula, the mining or extraction activity, and FORI would be determined by substituting FORI costs in the numerator of the second formula, the non-mining or non-extraction activity. In applying these formulas to determine FOGEI, gross sales would be the sales of the extracted oil or gas product.

(7) Classification of Assets as FOGEI and FORI Assets.

- Based on a review of applicable statutes and regulations (see Attachment 1 below), certain assets used with respect to producing wells and converting raw well effluent into marketable crude oil and natural gas should be classified as FOGEI assets. Examples of FOGEI assets include:
 - Wells, wellheads, and pumping equipment;
 - Flowlines (see Attachment 1), headers, and manifolds;
 - Desilters and other vessels to remove solid contaminants;
 - In the case of oil production, slug catchers, separators, treaters, emulsion breakers, and stock tanks needed to obtain marketable crude oil;
 - In the case of gas production, primary separation and dehydration equipment needed to arrive at a gaseous stream in which natural gas, condensate, and other hydrocarbons can be recovered;
 - Equipment needed to produce, transport, and inject fluids and gasses into the wells or reservoir;
 - Lines that interconnect above-listed equipment (see Attachment 1);
 - Instrumentation, metering, safety, control, utility, power, and other infrastructure-type equipment to provide for operation of the above; and

- Structures to physically support the above equipment, such as offshore platforms.

(8) Examples of FORI assets include:

- In the case of gas production, lease equipment beyond the primary separator and dehydrator to recover natural gas, condensate, and other hydrocarbons;
- Lines that carry natural gas beyond the primary separator and dehydration equipment and towards its sales point, as well as compressors needed to transport natural gas through these lines;
- Lines that carry marketable crude oil from the premises, as well as pumps needed to transport crude oil through these lines; and
- Assets used to process crude oil and natural gas.

(9) Taxpayers may allocate assets that support both FOGEI and FORI activities by any reasonable method. Examples of reasonable methods of allocation include the following:

- A compressor that is used to send natural gas to market (a FORI activity) and also to a reservoir for pressure maintenance (a FOGEI activity, see Attachment 1) may be allocated based on relative throughput; and
- An offshore platform that supports both primary separation of gases and liquids (a FOGEI activity) and the recovery of condensate from natural gas (a FORI activity, see Attachment 1) can be allocated based on relative space or weight.
- Most of the disagreements regarding classification of assets between FOGEI and FORI involve transportation and processing assets. Attachment 1 provides a more detailed discussion of the classification of those assets as FOGEI or FORI based on definitions provided in the regulations and on common usage of terms within the oil and gas industry.

(10) Attachment 1: Discussion of Classification of Assets as FOGEI or FORI.

(11) Meaning of Extraction for IRC § 907 and the regulations:

- A key to interpreting the IRC § 907 regulations is to understand the full meaning of certain terms and phrases:
- **FOGEI.** Defined at Treas. Reg. § 1.907(c)-1(b)(1) as:
- Taxable income (or loss) derived from sources outside the United States and its possessions from the extraction (by the

taxpayer or any other person) of minerals from oil or gas wells located outside the United States and its possessions or from the sale or exchange of assets used by the taxpayer in the trade or business of extracting those minerals.

- **Amount of FOGEI.** Defined at Treas. Reg. §1.907(c)-1(b)(2) as:
- The gross income from extraction is determined by reference to the fair market value of the minerals in the immediate vicinity of the well.
- **Minerals.** Defined at Treas. Reg. §1.907(c)-1(f)(1) as:
- The term "minerals" means hydrocarbon minerals extracted from oil and gas wells, including crude oil or natural gas (as defined in section 613A (e)). The term includes incidental impurities from these wells, such as sulphur, nitrogen, or helium. The term does not include hydrocarbon minerals derived from shale oil or tar sands.
- **Crude oil and natural gas.** IRC § 613A(e) and the underlying regulations provide the following definitions:
- IRC § 613A(e)(1) Crude oil. The term "crude oil" includes a natural gas liquid recovered from a gas well in lease separators or field facilities.
- Treas. Reg. § 1.613A-7(g) Crude oil. For purposes of IRC § 613A and the regulations under that section, the term "crude oil" means--
- A mixture of hydrocarbons which existed in the liquid phase in natural underground reservoirs and which remains liquid at atmospheric pressure after passing through surface separating facilities,
- Hydrocarbons which existed in the gaseous phase in natural underground reservoirs, but which are liquid at atmospheric pressure after being recovered from oil well (casing head) gas in lease separators, and
- Natural gas liquid recovered from gas well effluent in lease separators or field facilities before any conversion process has been applied to such production.
- IRC § 613A(e)(2) Natural gas. The term "natural gas" means any product (other than crude oil) of an oil or gas well if a deduction for depletion is allowable under IRC § 611 with respect to such product.
- Treas. Reg. § 1.613A-7(b) Natural gas. The term "natural gas" means any product (other than crude oil as defined in Treas.

Reg. § 1.613A-7(g)) of an oil or gas well if a deduction for depletion is allowable under IRC § 611 with respect to such product.

- **Immediate vicinity of the well.** Not defined in IRC § 907 or the regulations under that section. However, the term has been used for many decades for determining gross depletable income for purposes of depletion:
- Treas. Reg. § 1.613-3 Gross income from the property--Oil and gas wells. In the case of oil and gas wells, "gross income from the property", as used in IRC § 613(c)(1), means the amount for which the taxpayer sells the oil or gas in the immediate vicinity of the well. If the oil or gas is not sold on the premises but is manufactured or converted into a refined product prior to sale, or is transported from the premises prior to sale, the gross income from the property shall be assumed to be equivalent to the representative market or field price of the oil or gas before conversion or transportation.
- The term "immediate vicinity of the well" would have a meaning for IRC § 907 that is substantially identical to the meaning for depletion. Accordingly, FOGEI is the value of minerals at the bounds of the premises. The IRC § 907 regulations support this conclusion:
- Under Treas. Reg. § 1.907(c)-1(b)(6), the facts and circumstances that may be taken into account in determining the fair market value of oil or gas in the immediate vicinity of the well include the facts and circumstances pertaining to any difference in the producing country between the field and port prices. Within the depletion regulations, the representative market and field price (RMFP) must be determined when oil or gas is not sold in the immediate vicinity of the well. The RMFP is determined via a survey of representative wellhead sales of oil or gas as the case may be. Representative sales normally include sales after the above described tasks have been completed.
- The IRC § 907 regulations refer to the definition of crude oil from IRC § 613A (see above). The definition in Treas. Reg. § 1.613A-7(g) refers to liquid hydrocarbons that have passed through lease and field separation facilities.
- For crude oil, Treas. Reg. § 1.907(c)-1(d)(4) defines processing as the destructive distillation, or a process similar in effect to destructive distillation, of crude oil into its primary products including processes used to remove pollutants from crude oil. Treas. Reg. § 1.907(c)-1(d)(5) defines primary product from oil

as all products derived from the processing of crude oil, including volatile products, light oils (such as motor fuel and kerosene), distillates (such as naphtha), lubricating oils, greases and waxes, and residues (such as fuel oil).

- The processing of crude oil described in the IRC § 907 regulations does not take place on the premises, except in very rare situations. The field separation and treatment steps do not generally yield any of the primary products from oil described in Treas. Reg. § 1.907(c)-1(d)(4).
- Treas. Reg. § 1.907(c)-1(f)(6) also indicates that income from an insurance policy for business interruption may be extraction income to the extent the payments under the policy are geared directly to the loss of income from production. This is further indication that extraction and production are essentially synonymous.

(12) Meaning of Transportation:

- IRC § 907(c)(2) and Treas. Reg. § 1.907(c)-1(a)(5) states that FOGEI does not include income to the extent attributable to marketing, distributing, processing, or transporting minerals or primary products. Treas. Reg. § 1.907(c)-1(d)(2) defines "transportation" as--
- Carrying minerals or primary products between two places (including time or voyage charter hires) by any means of transportation, such as a vessel, pipeline, truck, railroad, or aircraft.
- Thus, an extremely literal view of transportation would question the correctness of treating flowlines and interconnecting lines as FOGEI assets. However, these specific types of lines are carrying raw effluent to and through the field treatment facilities so that it can be converted to crude oil and natural gas.
- There are other situations where assets that are transporting minerals (especially natural gas) are properly classified as FOGEI assets. Piping natural gas to or within a producing field for the purpose of directly enhancing extraction of additional minerals from the wells is a prime example. The use of natural gas to directly enhance extraction activity can occur in several ways such as:
- To fuel the engines on oil well pumps, or to generate electricity for the same end purpose;

- For use in "gas-lift" operations where gas is injected into the production string of oil wells (not the reservoir) to lighten the fluid load and lift fluids towards the wellhead; and
- To be injected into the reservoir to increase pressure and drive fluids towards producing wells. This is similar to the process of water flooding.

(13) Meaning of Processing:

- At IRC § 907(c)(2)(A), processing is listed as a FORI activity and is defined at Treas. Reg. § 1.907(c)-1(d)(4) as:
- The destructive distillation, or a process similar in effect to destructive distillation, of crude oil and the processing of natural gas into their primary products including processes used to remove pollutants from crude oil or natural gas.
- The processing of crude oil into its primary products has been discussed earlier. For gas, the primary products are defined at Treas. Reg. § 1.907(c)-1(d)(6) as:
- All gas and associated hydrocarbon components from gas wells or oil wells, whether recovered at the lease or upon further processing, including natural gas, condensates, liquefiable petroleum gases (such as ethane, propane, and butane), and liquid products (such as natural gasoline).
- As a result, an activity that normally occurs on the premises (i.e., the recovery of condensate "at the lease") is processing within the meaning of the IRC § 907 regulations so that any assets associated with that activity would be FORI assets.

FF. Exhibit 33: Employment Tax and the Employees on the U.S. Outer Continental Shelf

- (1) This exhibit provides guidance on the application of IRC § 3402, the Federal Insurance Contributions Act (FICA) and the Federal Unemployment Tax Act (FUTA) (collectively, employment tax) to remuneration for work performed on the Outer Continental Shelf, in the Gulf of Mexico (the OCS).
- (2) Background/Strategic Importance:
 - Our research indicates that many employers are not complying with their federal employment tax obligations for nonresident alien individuals they employ on the OCS. Under IRC § 871(b), nonresident alien employees are subject to income tax on compensation effectively connected with the conduct of a trade or business within the United States. Nonresident alien employees that perform services on structures permanently or

temporarily attached to the OCS, or on vessels or other devices engaged in activities related to the exploration for, or exploitation of, natural resources on the OCS, are generally engaged in a U.S. trade or business. See IRC §§ 864(b), 638(1); Treas. Reg. § 1.638-1(a), (c).

- Section 1441 provides for a 30% withholding tax on the gross amount of salaries, wages, compensation, remuneration, or other fixed or determinable annual or periodic income derived by a nonresident alien employee from U.S. sources. Withholding under IRC § 1441 is not required to the extent it is required under IRC § 3402. IRC § 1441(c)(4); Treas. Reg. § 1.1441-4(b)(1).
- Under IRC § 3402, every employer making a payment of wages must withhold income tax. “Wages” for purposes of withholding generally includes all remuneration for services performed by an employee for an employer. IRC § 3401(a). However, wages for this purpose does not include remuneration for services performed within the United States by a nonresident alien employee after December 31, 2000, if the remuneration is, or will be, exempt from income tax under a provision of the Code or an income tax treaty to which the United States is a party. Treas. Reg. § 31.3401(a)(6)-1(f). An employer may not exempt wages from withholding tax under an income tax treaty unless it receives a Form 8233, Exemption from Withholding on Compensation for Independent (and Certain Dependent) Personal Services of a Nonresident Alien Individual, from its nonresident alien employee. Treaty claims must be examined closely because certain treaties have special provisions that relate to the offshore oil and gas industry.
- In the absence of a treaty exemption from federal income tax withholding, a nonresident alien employee may claim withholding allowances on Form W-4, Employee’s Withholding Allowance Certificate. Notice 2005-76, 2005-2 C.B. 947, provides special rules for nonresident alien employees to use to complete Form W-4 and for employers to determine how much income tax to withhold from wages paid after December 31, 2005 under IRC § 3402. Notice 2009-91, 2009-48 I.R.B. 717, modifies Notice 2005-76 for wages paid to nonresident alien employees on or after January 1, 2010, through the end of calendar year 2010 only. Notice 2011-12, 2011-08 I.R.B. 717, announced that Notice 2009-91 has no effect for wages paid on or after January 1, 2011. Therefore, the modification to Notice 2005-76 made by Notice 2009-91 only applies for calendar year 2010 and does not apply for wages paid on or after January 1,

2011. Notice 2005-76 remains effective for wages paid on or after January 1, 2011. Generally, a nonresident alien employee is only entitled to claim one withholding allowance on Form W-4. If the nonresident alien employee does not furnish a fully completed Form W-4 to his or her employer, the employer is required to withhold as if the nonresident alien employee were a single person with no withholding allowances.

- Sections 3101 and 3111 contain FICA tax provisions for employees and employers. FICA tax is calculated as a percentage of wages and imposed in addition to other taxes on those wages. IRC §§ 3101, 3111, and 3121(a). Wages that are covered by a totalization agreement, as evidenced by a certificate of coverage issued by a foreign country, are exempt from FICA tax. The Social Security Administration's [website](#) provides a list of countries with which the United States has entered into a totalization agreement.
- An employer is liable for FUTA tax in an amount equal to a certain percentage of total wages paid by the employer during the calendar year. IRC §§ 3301, 3306. The employer is subject to FUTA without regard to whether it is required to make contributions to, or its employees are eligible to receive benefits under, a state unemployment compensation law. Rev. Rul. 75-87, 1975-1 C.B. 325. An employer is never exempt from FUTA under a treaty or totalization agreement.
- For purposes of FICA and FUTA, wages include all remuneration for employment. IRC §§ 3121(a), 3306(b). Employment includes, with certain specified exceptions, any service performed by an employee for an employer, within the United States for an employer regardless of the citizenship or residence of either. IRC §§ 3121(b), 3306(c). Services performed within the United States include services performed on the OCS. See, e.g., Rev. Rul. 86-108, 1986-2 C.B. 175. Employment does not include services performed by an individual on or in connection with a vessel that is not an American vessel if certain conditions are met. See IRC §§ 3121(b)(4), 3306(c)(4); Treas. Reg. §§ 31.3121(b)(4)-1(d), 31.3306(c)(4)-1(d).

(3) Planning and Examination Guidance:

- Chief Counsel Advice (CCA 201027046) dated June 4, 2010, addresses the applicability of employment taxes to remuneration received by nonresident alien employees for services performed on the OCS.

- An OCS compliance steering committee has been established to help identify, develop, resolve, and improve Service coordination of issues related to OCS activities. In addition, to facilitate the proper calculation of employment tax, OCS employers are advised to provide all information related to OCS employment tax obligations directly to the examiner instead of filing delinquent returns with the Campus Centers. Quarterly employment tax periods during which an OCS employer had no employees working on the OCS should be accounted for by placing zeroes on the appropriate report. Employers with a continuing presence on the OCS should file future quarterly employment tax return Forms 941 by using zeroes for any quarterly period during which they had no employees actually working in the OCS.
- Examiners who are contacted by employers with questions about employment tax obligations for individuals employed on the OCS should notify the OCS compliance steering committee of the contact.
- Questions should be directed to the appropriate IRS specialists.

(4) Examiners assigned OCS cases are required to complete the following actions:

- Secure OCS compliance steering committee approval on whether to assert penalties prior to any discussion with the taxpayer; and
- Input mandatory Uniform Issues List (UIL), Project, and Tracking codes.
- These requirements will remain in place until all cases assigned to the field have been completed or until such time as the issue owner executive issues a directive eliminating these requirements.

(5) Planning and Examination Risk Analysis:

- The field should address all relevant issues, including an employer's solicitation of Forms W-4, withholding, reporting, and payment of employment tax, and claims for tax exemption under an income tax treaty or totalization agreement. Examiners should challenge arguments by taxpayers who have not complied with the provisions of the Code relating to employment tax.

(6) Issue Tracking: Project Code 0555; Tracking Code 1555.

(7) Project established UIL Codes:

- 638.03-01. US Outer Continental Shelf (OCS) - US Flag vessels engaged in Oil & Gas Exploration, Repair, or Maintenance.
- 638.03-02. US Outer Continental Shelf (OCS) - Foreign Flag vessels engaged in Oil & Gas Exploration, Repair, or Maintenance.
- 638.04-01. US Outer Continental Shelf (OCS) - Foreign Flag vessels engaged in Bareboat Charter Rents.
- 861.04-01. Compensation for Services - Place where Services Performed.
- 864.01-01. Definition of Trade or Business - Personal Services.
- 1441.05-01. US Outer Continental Shelf (OCS) - Withholding on Foreign-Flag Vessels engaged in Bareboat Charter Rents.
- 1441.05-02. US Outer Continental Shelf (OCS) - Withholding on Foreign-Flag Vessels engaged in Time or Voyage Charters for Services.
- 3401.01-06. US Outer Continental Shelf (OCS) - Income tax withholding, FICA, & FUTA for Foreign Employees working on Oil & Gas Rigs.
- 3401.01-07. US Outer Continental Shelf (OCS) - Income tax withholding, for Foreign Employees Working on Foreign Flag Vessels.
- 3402.05-00. Withholding Exemptions and Exemption Certificates.

(8) This exhibit is not an official pronouncement of the law and cannot be used, cited, or relied upon as such.

GG. Exhibit 34: Cost Depletion Deductions Claimed for Oil and Gas Mineral Property

(1) Primary Legal Citations:

- IRC § 611 - General Rules covering Depletion; Treas. Reg. § 1.611-2(c) Determination of Mineral Contents of deposits.
- IRC § 612; Treas. Reg. § 1.612-1. - Basis for allowance of cost depletion.
- IRC § 614; Treas. Reg. § 1.614-1 Definition of Property.

(2) Case Conditions:

- Taxpayer is not qualified for the Independent Producer or Royalty Exemption under IRC § 613A(c). No computation for percentage depletion is allowed.
- Taxpayer has claimed Safe Harbor under Rev. Proc. 2004-19, 2004-1 C.B. 563.

(3) Audit Procedures:

- Using Corptax or Trial balances, summarize the depletion deductions reported for each entity and reconcile these costs to the amounts claimed on Form 1120.
- Identify all depletion deductions reported on partnership returns.
- Review summary list and select entities for further review.

(4) Request detailed depletion schedules that provide:

- A property number;
- A lease description;
- The lease's state and county;
- Original cost basis of the lease;
- Lease cost additions during the year;
- Lease cost retirements during the year;
- Beginning depletion reserve;
- Net beginning depletable basis;
- Designation of primary product;
- Mineral reserve estimate at the beginning of the year;
- Production of primary mineral during the year;
- Depletion rate computed;
- Depletion amount determined;
- End of year depletion reserve; and
- End of year net Depletable basis.
- From the list provided in response to the above request, analyze the data to identify:
- Properties that claim a very high depletion rate that nearly (or completely) provides a complete recovery of the net basis

remaining for the property [Issue: Mineral reserve or Annual Production data];

- Properties that report \$1 million or more for their annual depletion deduction (Or choose a parameter that better defines your taxpayer's data set) [Issue: Mineral reserve or Annual Production data];
 - Properties that report new property additions [Issue: Verify cost basis];
 - Properties that report retirements of cost basis and/or changes in the depletion reserve balances [Issue: Verify cost basis];
 - Property descriptions that appear multiple times in the data set, indicating that there may be multiple "Separate Properties" defined for a single property [Issue: Taxpayer may have inadvertently carved out a property leaving the production on Property A and the basis on Property B which has a very high depletion rate]; and
 - Similar property descriptions appear in multiple business units [Issue: Basis allocation of property to business units].
- (5) Compare Beginning Basis in Year 1 to the Beginning Basis in Year 2 to understand the growth or decline of the mineral property owned by the company [Issue: Acquisition or sale of major properties occurred. Valuation of property needed for sale or Like-kind Exchange].
- (6) Develop the "Basis Issues" for New additions, Retirements, Intercompany merger or transfer, and Major Sales or Acquisitions:
- Request details of the transactions that reflect New Additions. Identify any valuation step-up of the basis of properties;
 - Trace the property retirement to the abandonments claimed on the returns; and
 - Request any appraisals used for the major sales/acquisitions.
- (7) Conduct a reserve analysis to verify the value estimate reported by the taxpayer in the study.
- (8) Review the valuation assumptions used in the appraisal report that covers the escalation of oil and/or gas prices, discount factors, risk, and other valuation parameters.
- (9) Trace the acquisitions to the non-productive and productive lease accounts.
- (10) Conduct a Like-Kind-Exchange examination, as needed, for properties traded:
- Request any appraisals used for the Like-Kind-Exchange;

- Conduct a reserve analysis to verify the value estimate reported by the taxpayer in the study; and
- Review the valuation assumptions used in the appraisal report that covers the escalation of oil and/or gas prices, discount factors, risk, and other valuation parameters

(11) Mineral Reserve Estimates - Limitations with the Safe Harbor

- IRS has the right to spot check the Taxpayer's reserve estimate to ensure that the Taxpayer has included all of the Proven Developed and Proven Undeveloped mineral reserve estimates reported.
- Production reported for the property is not covered by Rev. Proc. 2004-19.
- For properties selected:
 - Request API numbers, Identify State, County, Township & Range or OCS lease number for all properties under review;
 - Provide data to an IRS engineer to review. Engineers can access a third-party data service or State website to obtain production information; and
 - Use data to compare to the Taxpayer's schedules and request Taxpayer to explain any differences between the volumes reported to the regulatory agency and the amounts reported on the tax return schedules.

GG.1. Exhibit 36: Accounting Method Changes

- (1) This Exhibit provides guidance on accounting method changes. Section 446 governs the general rules for methods of accounting. The two basic concepts are timing and consistency. If the accounting practice does not permanently affect the taxpayer's lifetime taxable income, but changes or could change the taxable year in which taxable income is reported, it involves timing. Therefore, the practice is considered a method of accounting. Although a method of accounting may exist without a pattern of consistent treatment of an item, in most instances, a method of accounting is not adopted without consistent treatment. Treas. Reg. § 1.446-1(e)(2)(ii)(a).
- (2) For a method of accounting to be adopted, the focus is on the actual treatment on the tax return. A taxpayer may adopt any permissible method of accounting for a material item by treating the item properly on the first return that reflects the item. Treas. Reg. § 1.446-1(e)(1). To be considered as having adopted an impermissible method of accounting, the taxpayer must improperly treat the material item the same way on two or more consecutively filed returns. Rev. Rul. 90-38, 1990-1 C.B. 57. Thus, a taxpayer adopts a permissible method by

properly treating a material item on its first return, and may thereafter change its method only with permission from the Service. If the taxpayer reports the material item incorrectly only once, it may make the change as the correction of an error. If an impermissible method is reported on two or more consecutively filed returns, the taxpayer must seek permission from the Service to change its method of accounting.

- (3) Once a method of accounting has been adopted, it may only be changed with the consent of the Commissioner. IRC § 446(e). A change in method of accounting includes a change in an overall plan of accounting (e.g., cash to accrual), or a change in the treatment of any material item. For accounting method purposes, a “material item” is any item that involves the proper time for the inclusion of the item in income or the taking of a deduction. For example, the treatment of a capital expenditure, recovered through depreciation, versus a current repair expense is a material item. Treas. Reg. § 1.446-1(e)(2)(ii)(d)(2).
- (4) A taxpayer may voluntarily request consent to change a method of accounting by filing a Form 3115. Rev. Proc. 2015-13, 2015-5 I.R.B. 419 provides the general procedures under § 446 to obtain both non-automatic consent as well as automatic consent of the Commissioner to change a method of accounting.
- (5) An examining agent who determines that a taxpayer’s method of accounting is impermissible may propose an adjustment with respect to that method only by changing the taxpayer’s method of accounting. Rev. Proc. 2002-18, 2002-1 C.B. 678, provides guidance for Service-initiated (involuntary) method changes and the basis for such changes.

HH. Exhibit 37: Glossary of Oil and Gas Industry Terms

- (1) Below are terms an IRS examiner might encounter during the examination of an oil & gas company. If an unlisted term is encountered, contact a Petroleum Industry Specialist or review other industry glossaries.
 - **American Petroleum Institute (API):** The largest U.S. trade association for the oil and natural gas industry. It claims to represent nearly 600 corporations involved in production, refinement, distribution, and many other aspects of the petroleum industry. One of API’s functions is the establishment and certification of industry standards.
 - **Ask:** The price at which a commodity or security is offered for sale.
 - **Assignment of Lease:** A legal document transferring all or a portion of the operating rights of a lease.
 - **Balancing:** The process by which persons having an interest in production adjust their take therefrom to ensure each interest holder receives his or her proportionate part of production.

- **Barrel (BBL):** A standard measure of volume for crude oil and liquid petroleum products. A barrel is 42 U.S. gallons.
- **Basic Sediment and Water (BS&W):** A combination of impurities and water that is often produced with crude oil. BS&W is heavier than oil and will settle to the bottom of a tank of produced oil.
- **Bid:** An offer to buy securities or a specific quantity of a commodity.
- **Bit:** A drilling tool that cuts a hole.
- **Bitumen:** A naturally occurring viscous mixture, mainly of hydrocarbons heavier than pentane, that may contain sulfur compounds and that, in its natural occurring viscous state, is not recoverable at a commercial rate through a well. Typically used to refer to the hydrocarbon material in Canadian oil sands.
- **Black Oil:** A general term used to describe liquid crude oil or heavy fuel oils. (Also referred to as “dirty cargoes”.) It is necessary to clean a tank car, storage tank, etc., that has contained black oils before it can be used for clean fuels.
- **Blow Out:** A sudden, violent expulsions of oil and gas from a drilling well, followed by an uncontrolled flow from the well.
- **BOE:** Barrel of Oil Equivalent. A unit which expresses volumes of natural gas in terms of equivalent barrels of oil. IRC § 613A(c)(4) and IRC § 776(b)(3)(B) equate 6 MCF of natural gas to 1 barrel of oil.
- **Bonus:** The consideration received by the lessor or sublessor upon execution of an oil or gas lease.
- **Bonus Exclusion Rule:** A rule that is designed to prevent a percentage depletion deduction, by both a lessor and lessee, on the same production. The rule provides that the taxpayer (lessee) who paid the bonus must exclude an allocable part of the bonus when computing “gross income” and “taxable income” from the property for purposes of determining the amount of the percentage depletion allowance. See Treas. Reg. § 1.613-2(c)(5)(ii), Rev. Rul. 79-73, 1979-1 C.B. 218, and Rev. Rul. 81-266, 1981-2 C.B. 139.
- **BOP:** Blow Out Preventer. A large device located on top of a well that helps the drilling crew control a blow out or a pending blow out. Within the BOP is a series of valves, “rams” and “shears” that are designed close in specific situations.
- **Bottom-Hole:** The lowest or deepest part of a well.

- **Bottom-Hole Contributions:** Money or property given to an operator for use in drilling a well on property in which the payor has no property interest. The contribution is payable when the well reaches a predetermined depth, regardless of whether the well is productive or nonproductive. Usually, the payor receives geological data from the well.
- **British Thermal Unit (BTU):** A measure of the amount of heat required to raise the temperature of 1 lb. of water 1° F.
- **Bulk Petroleum Products:** Large volume of products normally transported by pipeline, rail tank, tank truck, barge or tanker.
- **Butane:** An inflammatory gaseous hydrocarbon belonging to the methane series. It is gaseous at ordinary atmospheric conditions, but it is readily convertible to a liquid state.
- **Cost, Insurance, and Freight (CIF):** (Included in the price quoted). Any price stated CIF is not gross depletable income because it includes insurance and freight.
- **Carbon Dioxide (CO₂):** An inert, noncombustible, odorless gas at normal temperature and pressure conditions. Small amounts are often contained in natural gas produced from wells. A small number of reservoirs in the U.S. contain pure or nearly pure CO₂. Pure CO₂ is a valuable resource employed in tertiary oil recovery methods. CO₂ is a major component of the exhaust (flue gas) caused by combustion of fossil fuels.
- **Carried Interest:** An arrangement where one co-owner of an operating interest incurs an obligation to pay all of the costs to develop and operate a mineral property, in exchange for the right to recoup this investment out of the proceeds of the first production from the property. After the investment is repaid, any subsequent production is split between the co-owners. The co-owners that are not obligated to pay for the development and operation hold a carried interest in the mineral property until the carrying party's investment is repaid.
- **Carved-Out Drill Site:** A site for drilling a single well. It is "carved out" of a large tract and is transferred in total, or in part, to an operator or operators who will drill a well on it. It is generally the smallest sized tract on which the state regulatory body will allow a well to be drilled. For example, the carved-out drill site may be 40 acres out of a 160- acre tract owned.
- **Carved-Out Oil or Gas Payment:** A payment in oil or gas assigned by the owner of an interest in oil and gas. The payment is to be paid out of a fractional part of the owner's interest and will run for a period less than the life of the interest

from which it was carved. Except for oil or gas production payments pledged for development, production payments are treated as loans.

- **Cash Price:** Price in the cash market for actual or spot commodities with delivery through customary market channels.
- **Casing:** Steel pipe placed in an oil or gas well. Its main function is to prevent the well walls from caving in and to protect the well bore and in-hole equipment. It also prevents oil from migrating into other porous zones.
- **Casing Point:** The point in time in the drilling of a well when drilling is completed, and the operator must decide to set casing and attempt to complete the well or plug it as a dry hole.
- **Casinghead Gas:** Gas produced from an oil well. The casinghead gas is usually taken off at a gas/oil separator.
- **Cementing:** The process by which a slurry of cement and water is placed in the well bore between the casing and the walls of the hole or another string of casing. The cement is forced behind the casing from the bottom up. It holds the casing in place and seals the producing zone off from other upper (possible “thief”) zones.
- **Cubic Foot (of gas) Equivalent:** The unit often used for gas production, when barrels of condensate or other liquids are converted to cubic feet of natural gas. Analogous to BOE.
- **Checkerboard Acreage:** Mineral interest situated in a checkerboard pattern. Generally, this is done to spread the risk, or to make sure the producer will have some ownership if production is found.
- **Christmas Tree:** An assembly of valves mounted on the casinghead through which oil and gas is produced. The christmas tree also contains valves for testing the well and for shutting it down if necessary. A subsea production system is similar to a conventional land tree except it is assembled complete for remote installation on the sea floor with or without diver assistance. The marine (“wet”) tree is installed from the drilling unit and anchored to foundation legs implanted in the ocean floor. The tree is then latched mechanically or hydraulically to the casinghead by remote control.
- **Common Carrier:** Any cargo transportation system that may be accessed by any appropriate shipper and all shippers are charged the same rate schedule. Many pipelines are common carriers.

- **Complete Payout:** Complete payout occurs when the owner of the operating interest completely recovers the cost of drilling, equipping, and operating a well from proceeds of production of that well. The term is commonly used in reference to carried interest arrangements.
- **Completion Cost:** Costs incurred, after the drilling of a well reaches total depth, in preparing the well for production; i.e., running and cementing the production casing, replacing drilling mud with completion fluid, perforating the casing, fracturing or acidizing the reservoir, installing the tubing and christmas tree, and swabbing the well.
- **Concession:** The operating right to explore for and develop oil and gas in a specific area in consideration for a share of production in kind (equity oil).
- **Condensate:** A light hydrocarbon liquid that is in a gaseous state in the reservoir but becomes liquid when temperature and pressure are reduced.
- **Contiguous Property:** Tracts that have a common boundary. Tracts that touch only at a common corner are not contiguous.
- **Continuing Interest:** An economic interest in an oil or gas property that entitles the holder to receive all or a portion of the oil and/or gas produced, or the proceeds from the sale of such oil and/or gas for the entire life of the property. A continuing interest is contrasted to a production payment, which must, by definition, have an economic life of shorter duration than the economic life of one or more of the properties it burdens.
- **Contract Price:** See Term Price.
- **Council of Petroleum Accountants Society of North America:** A non-profit professional organization that provides guidance and education on accounting issues in the oil and gas industry. Its members work for government agencies, universities, consulting firms, and oil and gas exploration and production companies.
- **Core:** A solid column of rock, usually from two to four inches in diameter, taken as a sample of an underground formation.
- **Crude Oil:** For income tax purposes, a mixture of hydrocarbons that exist in a liquid phase in natural underground reservoirs and which remains liquid at atmospheric pressure after passing through surface separating facilities. In the United States, crude oils are classified as paraffin base, naphthene base, asphalt base, or mixed base. The properties of the

residuum left from nondestructive distillation determine the appropriate classification.

- **Cushion Gas:** The gas required in a reservoir to maintain reservoir pressure.
- **Damage Payments:** Payments made to the landowner by the oil or gas operator for damages to the surface, to growing crops, to streams, or other assets of the landowner.
- **Day Rate:** An agreed rate per day to drill a well. This rate does not include additional cost for such items as drilling mud, site preparation, fuel, etc.
- **Decline Rate:** The rate at which the flow of oil or gas from a field falls as production proceeds.
- **Deferred Bonus:** A lease bonus payable in installments over a period of years. The deferred bonus is distinguishable from delay rentals because the deferred bonus payments are due even if the lease is terminated, while delay rentals are discontinued with the termination of the lease or when development activities begin.
- **Delay Rental:** Money payable to the lessor by the lessee for the privilege of deferring drilling operations or commencement of production during the primary term of the lease.
- **Delineation Well:** A well drilled to determine the boundaries of the field.
- **Depletion:** Treas. Regs. §§ 1.611 through 1.613A provide taxpayers with an annual deduction in respect of an oil, gas or geothermal property. Taxpayers are allowed the greater of cost depletion or percentage depletion with respect to each mineral property. The cost depletion allowance is a ratable recovery of basis as mineral is produced. Percentage depletion is an allowance based on a percentage (15 percent for oil and gas properties) of the taxpayer's gross income from the sale of oil and gas but limited to 100 percent of the net income of the property. See Gross Income from the Property.
- **Derrick:** A tower used in the drilling of oil and gas wells as support for the equipment lowered into the well.
- **Development Well:** A well drilled for production in an area where proven reserves are located.
- **Discovery Well:** The first oil or gas well drilled in a field revealing oil or gas deposits.
- **Disposal Well:** A well-used for disposal of saltwater.

- **Division Order:** A contract between all of the owners of an oil and gas property and the company purchasing production from the property. The contract sets forth the interest of each owner and serves as the basis on which the purchasing company pays each co-owner their respective share of the proceeds of the oil and gas purchased.
- **Drill Site:** The location at which a well is to be drilled. The “site” contains sufficient leasehold working interest acres to permit the drilling of one well.
- **Drilling Mud:** A special mixture of clay, water, and chemical additive circulated through the well bore during drilling. Its functions are to cool the drill bit, lubricate the drill pipe, protect against blowouts by holding back subsurface pressure, carry rock cuttings to the surface, and deposit mud cake on the wall of the hole to prevent the bore hole from collapsing.
- **Drilling Rig:** Generally, the actual equipment package used to drill a well, such as the derrick, draw works, rotary table, drill string, power system and mud system. May be permanently or temporarily installed on an offshore drilling platform. Permanently integrated into a Mobile Offshore Drilling Unit.
- **Dry Gas:** Natural gas composed of vapors with only small amounts of dissolved liquid. Dry gas generally is composed of almost 100% methane (CH₄). Often associated with the output of a natural gas processing plant and called “pipeline quality gas.” The raw natural gas from many wells does not meet this definition because it commonly contains small amounts of ethane, butane, propane, contaminants, and water vapor.
- **Dry-Hole:** A well drilled for the production of oil and gas that either did not penetrate any productive reservoirs, or only penetrated reservoirs that do not yield commercial quantities of oil or gas after the well is completed. See Nonproductive Well.
- **Dry-Hole Contributions (DHC):** Money or property paid by property owners to another operator drilling a well on property in which the payors have no property interest. Such contributions are payable only in the event the well reaches an agreed depth and is found to be dry. Usually, the payor receives geological data for this payment. DHC’s are a type of bottom-hole contribution.
- **Dual Capacity Taxpayer:** One who is subject to a foreign tax levy, but who also receives a specific economic benefit (directly or indirectly) from that foreign country. In the oil and gas

context, the most frequent concern is whether payments made by companies to the sovereign are income taxes or royalties.

- **Economic Interest:** In order to be eligible to obtain income tax benefits, such as depletion, a taxpayer must possess a legal or equitable ownership interest in the minerals in place and receive income from the extraction and sale of such minerals. The definition of “economic interest” found in Treas. Reg. § 1.611-1(b) is as follows: An economic interest is possessed in every case in which the taxpayer has acquired by investment any interest in mineral in place or standing timber and secures, by any form of legal relationship, income derived from the extraction of the mineral or severance of the timber, to which he must look for a return of his capital.
- **Energy Information Administration:** A branch of the U.S. Department of Energy that collects, analyzes, and disseminates information and reports about many types of energy and fuels.
- **Enhanced Oil Recovery (EOR):** Sophisticated recovery (production) methods for crude oil that go beyond the more conventional secondary recovery techniques of pressure maintenance and waterflooding. Analogous to tertiary recovery methods. See Treas. Reg. § 1.43-2(e). EOR methods that are widely used include CO₂ miscible flood, steam drive, steam soak, and hydrocarbon miscible flood. EOR methods are not restricted to secondary or even tertiary projects. Some operators initiate an EOR method with the start of production from a reservoir for operational reasons or to maximize ultimate recovery.
- **Excess Intangible Drilling Cost:** Paid or incurred in connection with producing wells, less the amount that would have been allowable for the taxable year had the costs been capitalized and recovered by cost depletion or straight-line 120-month amortization. See IRC § 57(a)(2).
- **Exchange Oil:** Name given to oils exchanged between companies. Company A has excess oil on the West Coast but needs oil on the East Coast. Company B has excess oil on the East Coast but needs oil on the West Coast. Rather than incur large transportation costs, Company A exchanges oil with Company B.
- **Expendable Wells:** Another name for exploratory and delineation wells drilled in relatively deep waters and which the operators have no intention of completing for production.

- **Expired Lease:** A lease that is no longer in force due to either an expiration of a time limit or nonpayment of delay rentals.
- **Exploration Rights:** Permission granted by landowners allowing others to enter upon their property for the purposes of conducting geological or geo- physical surveys. Sometimes called shooting rights.
- **Exploratory Well:** A well drilled in a nonproductive area in search of oil or gas deposits. Sometimes it is called a wildcat well.
- **Farm-in:** An arrangement whereby one working interest owner acquires an interest in a lease owned by another. Consideration for the transfer is usually an agreement by the transferee to pay all or part of the drilling and development costs, and the transferor frequently retains some interest.
- **Farm-out:** The same thing as a farm-in but seen from the opposite perspective. The arrangement is a farm-in to the one who acquires the interest and a farm-out to the one who transfers it.
- **Federal Energy Regulatory Commission:** The U.S. Agency that regulates interstate natural gas and oil pipelines.
- **Fee Interest:** The ownership of both surface and mineral rights.
- **Field (oil or gas):** An area consisting of one or more reservoirs that are generally related to the same geological feature or condition.
- **Field Price:** Posted price of oil taken from a specific field.
- **Flow Line:** Surface pipe through which oil or gas is pumped or flowed from the well to either processing equipment or storage facilities.
- **Footage Drilling Contract:** A well drilling contract that provides for payment at a specified price per foot for drilling to a certain depth.
- **Foreign Oil and Gas Extraction Income:** Taxable income derived from all sources outside the United States and possessions from the extraction of minerals from oil or gas wells, or taxable income from the sale or exchange of assets used by the taxpayer in the business of extracting minerals from oil or gas wells.
- **Foreign Oil Related Income:** Taxable income derived from sources outside the U.S. and its possessions from the processing of oil and gas into their primary products; the

transportation, distribution and sale of oil and gas and their primary products; the disposition of assets used in these activities, excepting the sale of the stock of any corporation; or the performance of any directly related services.

- **Forward Contract:** A transaction common to many industries, including commodity merchandising, in which the buyer and seller agree upon delivery of a specified quality and quantity of goods at a specified future date for a price agreed upon in advance or to be determined at the time of delivery.
- **Floating Production, Storage and Offloading (FPSO) Unit:** A vessel used for the processing of oil and gas production and for temporary storage of oil. May be designed to receive hydrocarbons produced from nearby platforms or a subsea template. Oil is usually offloaded onto another tanker but can be transported through a pipeline. Used frequently outside the United States. The first operation of an FPSO in the U.S. Gulf of Mexico was in 2012.
- **Free-Well Agreement:** A form of sharing arrangement in which one party drills one or more wells completely free of cost to a second party in return for an interest in the property.
- **Futures Contract:** A firm commitment to deliver or receive, at a specified price and grade, a specified quantity of a commodity during a designated month that is traded through an exchange.
- **Futures Price:** The price of a given commodity futures unit determined on a futures exchange, via open outcry or electronic trading.
- **Gas Payment:** A production payment payable out of gas.
- **Geological and Geophysical (G&G) Costs:** These costs are expended for the acquisition of information relative to subsurface formations. This information may be the result of interpretative work of geologists; seismic surveys; gravity meter surveys; magnetic surveys; core samples or any other method used in the industry. The costs are capital in nature and recovered via depreciation if incurred in the U.S. See IRC § 167(h). Foreign G&G costs are recovered via the methodology of Rev. Rul. 77-188, 1977-1 C.B. 76 and Rev. Rul. 83-105, 1983-2 C.B. 51.
- **Gravity:** Short for “Specific gravity”. It is a measure of the density of oil relative to water. In the oil industry, gravity is usually expressed in degrees API, which has a scale that is inversely proportional to specific gravity. Light oils have a high API gravity (e.g., 40° API). Heavy oils have a low API gravity

(e.g., 20° API). Extra-heavy oils have an API gravity near 10° API, which is the same density as water at 60°F. The API Gravity is calculated from the specific gravity at 60°F using a formula. $API\ Gravity = [(141.5 / \text{Specific Gravity at } 60^\circ F) - 131.5]$

- **Gross (vs. Net):** Items that are specific to a company, such as acreage under lease, wells operated, or estimated reserves, may be expressed on a gross or net basis. Gross basis typically implies the entire amount or volume. The net number of acres or wells is usually reflective of a company's working interest. The net amount of estimated reserves or income is usually reflective of a company's revenue interest (working interest less the burden of royalty, over-riding royalty, and net profit interests).
- **Gross Income from the Property:** Since crude oil and natural gas are normally sold directly at or near the wellhead, the gross sales from which the percentage depletion allowance is computed are usually the actual sales prices. When oil or gas is transported from the premises or converted into a refined or manufactured product prior to sale, the representative market or field price is used for purposes of computing percentage depletion. See Treas. Reg. §1.613-3.
- **Heavy Crude Oil:** Crude oil of 20° API gravity or less (adjusted to 60° F). There are perhaps billions of barrels of heavy oil still in place in the United States that require special production techniques, notably steam injection or steam soak, to extract them from the underground formations.
- **Hedge:** A transaction entered into primarily to manage price risk by taking a position in a financial product equal and opposite to an existing or anticipated cash position or by shorting a security similar and equal to one in which a long position has been established.
- **Held By Production (HBP):** A provision in a mineral lease (or other agreement) that grants the lessor the right to operate the property (or concession) as long as it produces a certain amount of oil or gas (usually each month). Sometimes abbreviated as "HBP."
- **Henry Hub:** A pipeline hub on the Louisiana Gulf coast. It is the delivery point for the natural gas futures contract on the New York Mercantile Exchange.
- **Horizontal Drilling:** The process of boring a vertical hole into the ground, but at a pre-determined depth directing the path of the bit so that the hole reaches a horizontal orientation at a depth that coincides with a specific geologic formation. The

boring of the horizontal section continues until the desired length of it is achieved.

- **Hydraulic Fracturing:** The process of forcing a fluid, usually water laden with a “proppant” such as sand into a gas or oil-bearing formation that has very low native permeability. The injection pressure is raised until such point that the formation “breaks down” or “fractures”, which allows the fluid to carry the proppant into the small cracks and fissures that are created. the proppant is designed to keep them from completely closing shut when the injection ceases and the pressure is released. During the “flow back” or “clean-up” period most of the injected fluid and some proppant is recovered. The result of the process is to allow oil and gas to more readily flow through the formation and into the well.
- **Hydrocarbon:** Any of the compounds made up exclusively of hydrogen and carbon in various ratios.
- **Hydrocarbon Gas Liquids (HGLs):** Is a term developed by the U.S. Energy Information Administration to encompass hydrocarbons that occur as gases at atmospheric pressure and as liquids under higher pressures. HGLs are found in raw natural gas and crude oil. HGLs are extracted from natural gas at natural gas processing plants and when crude oil is refined into petroleum products. Includes ethane, normal butane, isobutane, propane, natural gasoline, and refinery olefins.
- **Independent Producers and Royalty Owners Exemption:** An exemption from the denial of percentage depletion provided in IRC § 613A(a). This exemption is provided in IRC § 613A(c) and allows percentage depletion to be computed on up to 1,000 BOE per day of the taxpayer’s production. Independent Producers are defined in IRC § 613A(d) as producers who do not have more than \$5,000,000 in retail sales of oil or gas in a year and who do not refine more than an average of 75,000 barrels of crude oil per day during the year.
- **Injection or Input Well:** A well that is used to inject gas, water, LPGs, or other foreign substances under pressure into a producing formation to maintain sufficient pressure to produce the recoverable reserves.
- **In-Situ:** In terms of oil and gas production, “within the reservoir”, for example, using the *in-situ* combustion process to heat fluids and create pressure in the reservoir in order to recover additional quantities of oil.

- **Intangible Drilling and Development Costs:** Those expenditures which do not have a salvage value, and which are incurred in the drilling and deepening of an oil and gas well.
- **Integrated Oil Company:** A company engaged in all phases of the oil business, i.e., production, transportation, refining, and marketing. It frequently also includes petrochemicals/chemicals.
- **Independent Petroleum Association of America (IPAA).** The IPAA is dedicated to ensuring a strong, viable domestic oil and natural gas industry, recognizing that an adequate and secure supply of energy is essential to the national economy.
- **Jack-Up Rig:** A mobile drilling platform with extendible legs for support on the ocean floor.
- **Jobber:** A buyer of oil products from refiners for resale to retail outlets.
- **Joint Operating Agreement:** 1) An agreement between two owners or among several concurrent owners for the operation of a leasehold for oil, gas, or other minerals. The agreement calls for the development of the lease or the premises by one of the parties to the agreement, who is designated as operator or unit operator for the joint account. All parties share in the expenses of the operations and in the proceeds resulting from the development. 2) An agreement among adjoining landowners or leaseholders to develop a common pool, again sharing expenses and profits.
- **Joule:** A unit of energy. One joule is equivalent to 9.48×10^{-10} BTUs (.000948 BTU).
- **Landman:** A person engaged in securing oil and gas leases from landowners.
- **Lease Agreement:** The legal instrument by which a leasehold is created in minerals. A contract that, for a stipulated sum, conveys to an operator the right to drill for oil and gas. The mineral lease is not to be confused with the usual lease of land or a building.
- **Lease and Well Equipment:** Capital investment in items having a potential salvage value. Such items include the cost of casing, surface pipe, tubing, wellhead assemblies, pumping units, lease tanks, treaters, and separators.
- **Lease Bonus:** Consideration paid by the lessee to the lessor for executing the lease.

- **Leasehold Costs:** Costs of acquiring and holding a lease, such as the lease bonus, commissions paid to landmen, cost of title work, and capitalized delay rental payments.
- **Lifting Costs:** Costs of operating wells for the production of oil and gas (producing costs).
- **Limited Partnership:** A form of organization, frequently employed in financing oil and gas ventures, by which an investor of funds becomes a limited partner with limited liability and limited management rights. Under certain conditions the interests in a limited partnership can be publicly traded. Such as partnership is referred to as a Master Limited Partnership (MLP).
- **Line Fill:** The volume of product required in a liquids pipeline at all times to allow for normal operations. IRS examiners may also use the term to describe the volume of partially processed product within a refinery.
- **Line Pack Gas:** The volume of gas maintained in a pipeline to maintain minimum operating pressure.
- **Liquefied Natural Gas:** Composed almost entirely of methane. The temperature at which methane becomes liquid at normal pressure is -260° F. In liquid form, natural gas retains only 1/600 of its original volume.
- **Liquefied Petroleum Gas (LPG):** According to the U.S. Energy Information Administration, LPG is “[A] group of hydrocarbon gases, primarily propane, normal butane, and isobutane, derived from crude oil refining or natural gas processing. These gases may be marketed individually or mixed. They can be liquefied through pressurization (without requiring cryogenic refrigeration) for convenience of transportation or storage. Excludes ethane and olefins.” This definition is not used by the IRS for purposes of fuel excise taxes and credits.
- **M:** Readers should be aware that some parties (typically scientists and engineers) treat “M” as meaning *thousand*. To them “1 MCF” means one thousand cubic feet and “1 MMBTU” means one million British Thermal Units (because 1000 X 1000 is one million). Conversely, other parties (typically financial and accounting professionals) treat “M” as meaning *million*. To them, “\$1M” means one million dollars.
- **Marginal Production:** Domestic crude oil or natural gas that is produced from a stripper well property for the calendar year in which the taxable year begins, or oil produced from a property whose production is substantially all heavy oil during such

calendar year. See IRC § 613A(c)(6)(D), IRC § 613A(c)(6)(E) and IRC § 613A(c)(6)(F).

- **Marginal Wells:** A well of such low producing capacity that the profitability of future production is marginal. A specific definition is contained in IRC § 45I(c)(3) for the Marginal Well Tax Credit.
- **Mark to Market:** This is a procedure in which the broker debits or credits the available balances of customers' accounts daily for changes in the value of open contracts.
- **MCF:** Thousand cubic feet. According to the U.S. Energy Information Administration, natural gas can be priced in units of dollars per therm, dollars per MMBtu, or dollars per cubic feet (or per MCF). The heat content of natural gas per physical unit (such as Btu per cubic foot) is needed to convert these prices from one price basis to another. In 2019, the U.S. annual average heat content of natural gas delivered to consumers was about 1,037 Btu per cubic foot. Therefore, 100 cubic feet (Ccf) of natural gas equals 103,700 Btu, or 1.037 therms. One thousand cubic feet (MCF) of natural gas equals 1.037 MMBtu, or 10.37 therms.
- **Methane:** Methane (CH₄) is a simple gaseous hydrocarbon associated with petroleum. Natural gas used by residential and industrial customers is nearly 100 percent methane.
- **Mineral Deed:** A lease instrument that conveys an interest in minerals on or under a tract of land.
- **Mineral Interests (Mineral Rights):** The ownership of the minerals and the right to remove them from the property.
- **Minimum Royalty:** An obligation of a lessee to periodically pay the lessor a fixed sum of money after production occurs, regardless of the amount of production. Such minimum royalty may or may not be chargeable against the royalty ownership of future production.
- **MMBTU:** Million British Thermal Units.
- **MMCF:** Million cubic feet.
- **Mobile Offshore Drilling Unit:** Includes "jack-ups", "semi-submersibles", and "drill ships". Somewhat analogous to barges that hold a drilling rig, but much more sophisticated and versatile.
- **Mud Pit:** Tank near the drilling rig used for storage of drilling mud during drilling operations. The drilling mud is prepared for drilling in the pit by mixing the mud and water. Slush pumps

withdraw the mud from the pit and circulate it down the drill pipe. At the surface the mud passes back to the mud pit through the “shale shaker” which removes the drill cuttings that were carried to the surface by the mud.

- **Multiple Completion Well:** An oil and/or gas well completed in such a manner that it is capable of producing oil and/or gas separately from two or more reservoirs. Such separate production may be simultaneously through two or more strings of tubing or through a string of tubing and between the tubing and the casing.
- **Natural Gas:** Any hydrocarbon product (other than crude oil) of an oil or gas well if a deduction for depletion is allowable under IRC § 611 with respect to such product. Specifically, natural gas refers to any hydrocarbon gas.
- **Natural Gas Liquids:** Natural gas liquids are the heavier hydrocarbon liquids produced along with natural gas, including butane, propane, natural gasoline, and ethane. See also Hydrocarbon Gas Liquids.
- **Natural Gas Sold Under a Fixed Contract:** Domestic natural gas sold under a contract in effect on February 1, 1975, under which the price cannot be adjusted to reflect the increase in income tax due to the repeal of percentage depletion. See IRC § 613A(b)(3)(A).
- **Natural Resource Recapture Property:** For purposes of IRC § 1254, a mineral interest property which had depletion deductions or intangible drilling costs incurred with respect to it.
- **Net Profits Interest:** An interest in production created from the working interest and measured by a certain percentage of the net profits from the operations of the property.
- **Non-consent:** Term used to describe a member of a joint venture that declines to participate in an investment of the joint venture, such as drilling a particular well or completing a well after it reaches total depth. The joint venture agreement may allow the non-consenting member to regain its working interest in the well after the other members recoup their costs and a risk-reward (e.g., costs times 200 percent).
- **Nonconventional Source Fuels Credit:** A tax credit authorized by IRC § 45K for sales of qualified fuels (defined in IRC § 45K(c)) to unrelated persons.
- **Nonoperating Interest:** An economic interest that does not meet the definition of operating interest as defined in Treas.

Reg. § 1.614-2(b). A royalty, overriding royalty, or net profits interest is a nonoperating interest. A production payment has the attributes of a nonoperating interest, except that it is not a continuing interest. It may or may not be treated as an economic interest treatment. See IRC § 636 and the regulations thereunder.

- **Nonproductive Well:** The term used in the IRC § 57(a)(2)(B) and IRC § 263(i) and Treas. Regs. §§ 1.263A-13, 1.612-4, 1.612-5 and 1.1254-1 to describe a dry hole. See Dry Hole.
- **New York Mercantile Exchange:** A commodities futures exchange that lists several types of crude oil, natural gas, heating oil, gasoline, and ethanol.
- **Outer Continental Shelf (OCS):** In general, the offshore areas that are the domain of the U.S. government. Treas. Reg. § 301.9001-2 contains the formal definition: “OCS” means all submerged lands lying seaward and outside of the area of lands beneath navigable waters as defined in Section 1301 of Title 43 and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.
- **Offset Well:** Well drilled on one tract of land to prevent drainage of oil or gas to a nearby tract on which another well has been drilled.
- **Oil or Gas Property:** Each separate interest owned by the taxpayer in each mineral deposit in each separate tract or parcel of land.
- **Oil Payment:** A production payment payable from oil.
- **Oil Sands:** A term commonly used in Canada to describe heavy and extra heavy deposits of petroleum. Shallow deposits are recovered by mining. Deeper deposits are recovered by in situ methods. The term “tar sands” is more commonly used in the United States.
- **Oil Shale:** A sedimentary rock containing kerogen, a solid organic material. Liquid hydrocarbon can be obtained by retorting. See Rev. Rul. 92-100; 1992-2 C.B. 7 for the distinction between oil shale and liquid hydrocarbons (oil) that sometimes exists naturally in a shale formation.
- **Operating Mineral Interest:** A separate mineral interest in respect of which the costs of production of the mineral are required to be taken into account by the taxpayer for purposes of computing the 50 percent of taxable income from the property in determining the deduction for percentage depletion. See

Treas. Reg. § 1.614-2(b). The usual working or operating interest consists of seven-eighths of the production subject to all of the costs of drilling, completing, and operating the lease. See *L.W. Brooks Jr. v. Commissioner*, 424 F.2d 115 (5th Cir. 1970) and Treas. Reg. § 1.614-2(b). For oil and gas, IRC § 613(a) changed 50 percent of taxable income to 100 percent for years after 1990.

- **Operator:** The individual or company responsible for conducting exploration and production activities in a defined area. In a joint venture the operator is usually the holder of the largest operating mineral interest.
- **Overriding Royalty:** A right to a stated fraction of production, in kind or in value, created from the working interest, having a term coextensive with that of the working interest, but not burdened with development or operation costs.
- **Participating Area:** That part of a unit area which is considered reasonably proven to be productive.
- **Participation Agreement:** An agreement between two or more parties to share in the cost and production of a well.
- **Passive Activity:** Income/losses generated from an activity (trade or business) in which the taxpayer does not materially participate or from a rental activity, usually regardless of participation levels.
- **Pay:** The reservoirs or portion of reservoirs penetrated by a well that are expected to produce oil and gas in commercial quantities are called “pay sands”. Gross pay is the total thickness (usually measured vertically) of a pay interval. Net pay is gross pay less those portions that are not expected to produce hydrocarbons due to factors such as poor permeability.
- **Payout:** Recovery from the net proceeds of production of the entire cost of drilling, completing, and equipping a well.
- **Percentage Depletion:** The method of computing the depletion deduction based upon an arbitrary percentage of gross income from production (gross income from the property). The percentage depletion allowance is limited to 100 percent of the taxable income from oil and gas operations computed with respect to each separate operating mineral interest. Percentage depletion allows a taxpayer to deduct costs in excess of basis. See Treas. Reg. § 1.613-1(a).

- **Perforating:** The piercing of the casing wall and cement to provide holes through which the hydrocarbons may enter the well bore.
- **Permeability:** A measure of the resistance provided by the reservoir rock to the flow of fluids through it. Reservoir rock that allows fluids to easily flow through it has high permeability.
- **Petroleum:** Sometimes viewed as analogous to (liquid) crude oil. A more precise definition by the Society of Petroleum engineers is “Naturally-occurring liquids and gases which are predominately comprised of hydrocarbon compounds. Petroleum may also contain non-hydrocarbon compounds in which sulfur, oxygen, and/or nitrogen atoms are combined with carbon and hydrogen. Common examples of non-hydrocarbons found in petroleum are nitrogen, carbon dioxide, and hydrogen sulfide”. The non-hydrocarbons are considered impurities. See *Sour Oil or Gas*.
- **Platform:** A structure that supports assets such as wells, production equipment, a drilling rig, personnel accommodations, or combinations of those assets. Designed to stay at one site for many years. Platforms can either rest on the seabed or be of a floating design that is kept on location by positioning cables.
- **Pool of Capital:** Under this doctrine, a taxpayer contributing property, cash or drilling services to the drilling of an oil or gas well in return for an economic interest in that well makes a capital contribution to the “pool of capital” available to the venture. The taxpayer is considered to have received a capital interest in the well that was not taxable upon its receipt. See Rev. Rul. 77-176, 1977-1 C.B. 77.
- **Pooling:** The bringing together of small tracts sufficient for the granting of a well permit under applicable spacing rules, as distinguished from unitization which is the joint operation of a reservoir. Pooling is important to prevent the drilling of unnecessary and uneconomic wells. See Treas. Reg. § 1.614-8(b)(6).
- **Porosity:** A measure of the amount of void space (pores) in a unit of reservoir rock. Expressed as a percent. For example, a sample of rock that has a bulk size of 1.0 cubic feet and 15 percent porosity could hold 0.15 cubic feet of fluid.
- **Possible Reserves:** An incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Possible Reserves are those additional reserves which analysis of geoscience and engineering data suggest are

less likely to be recoverable than Probable Reserves. Possible Reserves are generally not consistent with minerals described in Treas. Reg. §1.611-2(c)(1).

- **Postproduction Costs:** Costs incurred by the operator between the point of production and the point of sale, such as for dehydration, compression, transportation, and storage. Disputes can arise when the operator charges the royalty owner for a share of these costs. State law varies as to what costs can be charged to a royalty owner.
- **Pour Point:** The lowest temperature at which an oil will pour or flow when chilled without disturbance under specified conditions. By American Society for Testing and Materials instruction, it is taken as the temperature 5° F above the solid point.
- **Primary Production:** Oil production which is recovered through the use of the natural energy source in the reservoir. Also called primary recovery.
- **Primary Term:** The period of time a lease may be kept in force even though no drilling operations have commenced. Payments of delay rentals may or may not be required. The time period varies.
- **Probable Reserves:** An incremental category of estimated recoverable volumes. Probable Reserves are those additional reserves that are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. Probable Reserves are generally consistent with minerals described in Treas. Reg. § 1.611- 2(c)(1)(ii). They are reasonably analogous to “probable and prospective” ores or minerals.
- **Producer:** One who owns an economic interest in a well that produces oil or gas.
- **Production Payment:** 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. See Treas. Reg. § 1.636-3(a)(1) & (2).
- **Production Taxes:** Taxes levied by state governments on mineral production based on the value and/or quantity of production. These are also referred to as severance taxes.

- **Project Area:** In the search for mineral producing properties, it is customary for a taxpayer to conduct geological and geophysical studies and surveys within a large geographical area (the project area). The purpose of these initial reconnaissance type surveys is to identify specific geological features with sufficient mineral producing potential to merit further exploration. The costs incurred with respect to these initial surveys are capital in nature. See Geological and Geophysical Costs for discussion of cost recovery.
- **Propane:** Propane (C₃H₈) is a gaseous hydrocarbon associated with petroleum. Commonly used for heating and cooking when natural gas (methane) is not available. When compressed to a moderate pressure it becomes a liquid, which facilitates transportation and storage.
- **Property:** Each separate interest owned by a taxpayer in each mineral deposit in each separate tract or parcel of land. See Treas. Reg. § 1.614-8.
- **Proved Reserves:** An incremental category of estimated recoverable volumes associated with a defined degree of uncertainty. Proved Reserves are those quantities of petroleum which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. Proved reserves correspond to the recoverable units described in Treas. Reg. § 1.611-2(c)(1).
- **Production Sharing Contract:** Commonly used outside the U.S. to explain the rights and obligations of the host government, national oil company, and other oil companies in regard to a specific area. Somewhat analogous to a combination of a lease and a joint operating agreement.
- **Pumping Unit:** The most common version is the pump jack used on onshore wells. Offshore oil wells use a “gas lift” system whereby gas is continuously injected into the tubing at specific depths to lessen the hydrostatic head of the produced fluids. Wells that need to produce a very high rate of fluids, such as wells with extremely high water- oil ratio, use an electrically powered submersible pump. Subsea flowlines which carry both oil and gas are sometimes boosted by “multiphase pumps”.
- **Recompletion:** The operation to change the productive interval of a well. Involves sealing off the previous interval with cement or a mechanical plug and perforating the new interval. May involve the installation of a new string of tubing or resetting the

existing string. Recompletions are usually done “up hole” to access “behind the pipe” reserves in shallower reservoirs that have not yet been produced by the well.

- **Reconnaissance Survey:** A survey of a project area utilizing various geological and geo-physical exploration techniques to identify specific geological features with sufficient mineral producing potential to merit further exploration. See Geological and Geophysical Costs for discussion of cost recovery.
- **Recoverable Reserves:** The total recoverable units (e.g., barrels or thousands of cubic feet) of ores or minerals reasonably known to exist in place as of the estimation date. The estimation of recoverable reserves must be made in accordance with the method current in the industry in light of the most accurate and reliable information obtainable. The estimation must be made in the first taxable year within which depletion is taken with respect to a mineral interest and the recoverable reserves can only be re-estimated if it is determined by operations or development work that the number of recoverable reserves are materially greater or less than the number remaining from the prior estimate. See Rev. Rul. 67-157, 1967-1 C.B. 154, G.C.M. 33140 (Nov. 24, 1965). Rev. Proc. 2004-19, 2004-1 C.B. 563, provides an elective safe harbor that taxpayers may use to determine recoverable reserves of its properties.
- **Reservoir:** A porous, permeable sedimentary rock containing commercial quantities of oil or gas.
- **Residue Gas:** Natural gas, mostly methane, which remains after processing in a separator or plant to remove liquid hydrocarbons contained in the gas when produced.
- **Retained Interest:** A special nonoperating interest retained by the lessor when the lessor transfers the responsibilities for developing the property to another party.
- **Reversionary Interest:** In a carried interest arrangement, the particular working interest percentage that the carried party regains after the carrying party recoups the costs it incurred as allowed by the agreement between the parties.
- **Representative Market or Field Price:** A weighted average price of oil or gas that takes into account all wellhead sales of gas, which is comparable to the gas of the producer-manufacturer in terms of quality, pressure, and location. See Gross Income from the Property and section VII.B.3 Gross Income from the Property.

- **Remotely Operated Vehicle:** A type of small, unmanned submarine that is used in deep-water drilling and construction activities.
- **Royalty:** A share of the gross production of the minerals (or a share of the proceeds from the sale thereof) on a property by the landowner without bearing any of the cost of producing the minerals. The usual landowner's royalty is one-eighth of gross production. See Treas. Regs. §§ 1.614-2(b) and 1.614-5(g).
- **Run Statement:** A statement supplied by the purchaser of oil or gas to an interest owner setting forth the gross volume of product taken, sales value, taxes paid, and net payment to the owner. The run statement usually accompanies the payment for the runs.
- **Run Ticket:** Evidence of receipt or delivery of oil issued by a pipeline or other carrier or purchaser.
- **Saltwater Disposal Wells:** Wells used for disposal of saltwater that is produced along with oil or gas.
- **Secondary Production:** Oil recovered by a secondary recovery method used to recover oil from a field by a means other than the normal pumping or flowing methods. This will normally involve the flooding of the formations through injection wells with water to drive the recoverable oil to producing wells.
- **Seismic Survey:** Geophysical information on subsurface rock formations gathered by means of a seismograph.
- **Separator:** A gas-oil separator is a cylindrical tank, usually located at or near the tank battery, which is used to separate oil and/or gas well effluent into liquids and gas at or near atmospheric pressure.
- **Severance Taxes:** See Production Taxes.
- **Shale:** A fine-grained, sedimentary rock composed of mud from flakes of clay minerals and tiny fragments (silt-sized particles) of other materials. Shale is normally impenetrable to fluid flow, and often forms the cap or seal that traps petroleum in underlying reservoirs. Some shales act as both the source and the reservoir of oil and gas. Advances in hydraulic fracturing and horizontal drilling have made it possible to economically produce oil or gas from certain shale formations.
- **Shale Gas:** Natural gas produced from a shale formation, often as a result of hydraulic fracturing and horizontal drilling.

- **Shale Oil:** Oil that naturally exists within a shale formation. See also Rev. Rul. 92-100, 1992-2 C.B. 7. Large amounts have been produced from domestic wells in recent years due to hydraulic fracturing and horizontal drilling. Many refineries in the U.S. were revamped to handle this “light crude” in lieu of imported “heavy crude.”
- **Sharing Arrangement:** A transaction where a person contributes to the acquisition, exploration, or development of an oil or gas property and receives as consideration an interest in the property to which the contribution is made.
- **Shooting Rights:** See Exploration Rights.
- **Short:** A trader obtains a short position by selling a security he does not own and making delivery with borrowed securities.
- **Shut-in Wells:** A producing well that has been closed down temporarily, or one that was never connected to a pipeline because of its very remote location.
- **Side Tracking:** An operation involving the use of an existing well to drill a second hole.
- **Sour Oil or Gas:** Oil or gas containing more than a certain proportion of hydrogen sulfide or other sulfur compounds, usually 0.5 percent or more.
- **Society of Petroleum Engineers (SPE).** SPE is a professional organization that collects, disseminates, and exchanges technical knowledge concerning the exploration, development and production of oil and gas resources and related technologies. SPE also provides opportunities for professionals to enhance their technical and professional competence.
- **Speculator:** An individual, or entity, that is not a hedger. One who trades for profits by anticipation of price movements.
- **Spot price:** The price at which a physical commodity is selling at a given time and place, often involving prompt delivery. Same as cash price. The spot price differs from a contract or term price in that the latter involves multiple sales over time, whereas the former usually involves a single cargo or transaction.
- **Spread (or Straddle):** The purchase of one futures delivery and the sale of another futures delivery month of the same or similar commodity, or the purchase of a commodity in one market against the sale of that commodity or a like commodity in another market to take advantage of differences or anticipated differences in price relationships.

- **Spud:** To start the actual drilling of a well.
- **Stripper Oil:** Oil recovered from a stripper well. See IRC § 613A(c)(6)(E).
- **Stripper Well Property:** A property where the average daily production of domestic crude oil and gas produced from the wells on the property during a calendar year divided by the number of such wells is 15-barrel equivalents or less. See IRC § 613A(c)(6)(E).
- **Subsea Production System:** Similar to the assets needed to carry production from onshore wells to processing equipment but located on the seabed instead. Subsea christmas trees are called marine trees or “wet trees”. A “jumper” carries production from an individual well to a subsea manifold. A subsea flowline then carries the production towards a platform for processing. The flowline transitions to a vertical “riser” as it approaches the platform. “Umbilical” lines run from a control center on the platform to each well and manifold in order to provide power, control, data communications, and chemicals.
- **Sweet Oil or Gas:** Crude oil or natural gas which contains little or no sulphur or hydrogen sulfide.
- **Take or Pay Contract:** A contract by which a pipeline company, within a specific period of time, must pay for an agreed number of units whether or not the units have been taken. The pipeline company usually has the right to take these units, within a specified time period, without further payment.
- **Tank Battery:** Two or more tanks connected together on a property to store oil production prior to sale and/or removal.
- **Tank Farm:** A number of oil storage tanks located together where oil gathered by a pipeline company is stored prior to transportation to the refinery. Refineries also have tank farms to hold crude oil waiting to be processed or final products waiting to be shipped.
- **Tar Sands:** Native asphalt, solid and semisolid bitumen, including oil-impregnated rock or sands from which oil is recoverable only by special treatment. Processes have been developed for extracting the oil, referred to as synthetic oil. See TAM 8940004 (June 20, 1989) and FEA Ruling 1976-4, 41 FED. Reg. 25, 886 (1976). See also “oil sands.”
- **Term Price:** A contract price, usually involving multiple deliveries over time. See Spot Price.

- **Tertiary Production:** A method used to recover oil after a secondary method has been applied, typically by injecting steam, solvents, or chemicals to modify the properties of the oil in the formation so that it will more readily flow towards production wells.
- **Tight Gas:** Natural gas produced from a “tight” formation (usually a sandstone) that requires hydraulic fracturing in order to produce in substantial quantities because of extremely low native permeability. Incentives formerly available under IRC § 45K led to substantial domestic production of gas from tight formations.
- **Top Lease:** The granting of a new oil or gas lease prior to the termination of an existing lease; the new lease becoming effective upon expiration of the old lease.
- **Tubing:** The pipe that is placed into the casing of a well and through which produced fluids flow to reach the wellhead. Common diameters are 2.5 inch to 4.5 inch.
- **Turnkey Well:** A completed well, drilled and equipped by a contractor for a fixed price.
- **Unit of Production Method:** A method for computing depreciation or amortization based on a ratable recovery of basis over the expected number of units to be produced by an asset. The method is similar to the computation of cost depletion.
- **Unitization:** A term denoting the joint operation of separately owned producing leases in a pool or reservoir. Unitization makes it economically feasible to undertake cycling, pressure maintenance, or secondary and tertiary recovery programs. See Treas. Reg. §1.614-8(b)(6).
- **Unrealized Profit or Loss:** The profit or loss on open positions that has not become actual. It is realized when the security or commodity futures contract in which there is a gain or loss is actually sold.
- **U.S. Department of Energy (DOE):** A cabinet-level department of the United States Government concerned with the United States' policies regarding energy and safety in handling nuclear material. Its responsibilities include the nation's nuclear weapons program, nuclear reactor production for the United States Navy, energy conservation, energy-related research, radioactive waste disposal, and domestic energy production.

- **Viscosity:** That property of a liquid which causes it to offer resistance to flow. The higher the viscosity of an oil the less readily it will flow; the lower the viscosity of the oil the more readily it will flow. Motor oil with a viscosity of SAE 10 will flow more readily than a SAE 20.
- **Volatility:** A measure of the propensity of a substance to change from the liquid or solid state to the gaseous state. A volatile liquid is one which readily vaporizes at comparatively low temperatures.
- **Volumetric Production Payment:** A production payment that is to be satisfied by delivery of a certain volume of hydrocarbons as distinguished from one to be satisfied by delivery of hydrocarbons of a specific value.
- **Waterflooding:** A method of secondary recovery, in which water is injected into an oil reservoir for the purpose of pushing the oil out of the reservoir rock and into the bore of a producing well.
- **Well Bore:** The hole that is created by the process of drilling.
- **Wellhead:** Equipment used to maintain surface control of a well. See Christmas Tree.
- **Wildcat Well:** A well drilled in an unproved area, far from a producing well; an exploratory well in the truest sense.
- **Working Interest:** See Operating Mineral Interest.
- **Workover Costs:** Similar to Recompletion Costs, but usually to establish or re-establish production from the same reservoir from which the well has produced. Typical activities include cleaning, re-acidizing, reperforating, recementing, replacing corroded tubing, and similar costs. They may be recurring type costs but usually not on an annual or shorter time basis.
- **West Texas Intermediate (WTI):** A crude stream produced in Texas and southern Oklahoma which serves as a reference or “marker” for pricing a number of other crude streams and which is traded in the domestic spot market at Cushing, Oklahoma. WTI is considered a light, sweet crude.