FEDERAL REGISTER

26 CFR Parts 1 and 602

Enhanced Oil Recovery Credit

[T.D. 8448]

RIN 1545-AP64

57 FR 54919

November 23, 1992

ACTION: Final regulations.

SUMMARY: This document provides final regulations relating to the enhanced oil recovery credit for certain costs that are paid or incurred in connection with a qualified enhanced oil recovery project. Changes to the applicable law were made by the Omnibus Budget Reconciliation Act of 1990. These final regulations provide the public with guidance in determining the costs that are subject to the credit, the circumstances under which the credit is available, and the procedures whereby a project is certified as a qualified enhanced oil recovery project.

EFFECTIVE DATE: November 23, 1992.Display Classification Information Display Classification Information Display Classification Information Display Classification Information Display Classification Information Display Classification Information Display Classification Information

FOR FURTHER INFORMATION CONTACT: Brenda M. Stewart of the Office of Assistant Chief Counsel (Passthroughs and Special Industries), 202-622-3120 (not a toll-free number).

TEXT: SUPPLEMENTARY INFORMATION:

Paperwork Reduction Act

The collection of information contained in this final regulation has been reviewed by the Office of Management and Budget in accordance with the Paperwork Reduction Act of 1980 *(44 U.S.C. 3504*(h)) under control number 1545-1292. The estimated annual burden per respondent or recordkeeper varies from 70 hours to 76 hours depending on individual circumstances, with an estimated average of 73 hours.

These estimates are an approximation of the average time expected to be necessary to collect required information. They are based on such information as is available to the Internal Revenue Service. Individual respondents or recordkeepers may require more time or less time, depending on their particular circumstances.

Comments concerning the accuracy of this burden estimate and suggestions for reducing this burden should be directed to the Internal Revenue Service, Attn: IRS Reports Clearance Officer T:FP, Washington, DC 20224, and to the Office of Management and Budget, Attention: Desk Officer for the Department of the Treasury, Office of Information and Regulatory Affairs, Washington, DC 20503.

Background

On December 30, 1991, proposed regulations concerning the costs eligible for the enhanced oil recovery credit provided in *section 43 of the Internal Revenue Code* and the circumstances under which the credit is available were published in the Federal Register *(56 FR 67256* (December 30, 1991)). These amendments were proposed to conform the regulations to section 11511 of the Omnibus Reconciliation Act of 1990, Public Law 101-508.

Rules concerning procedures for certification of a project as a qualified enhanced oil recovery project were published as temporary regulations *(56 FR 67176* (December 30, 1991)).

A public hearing was held on April 7, 1992. After considering all comments regarding the proposed regulations, the proposed regulations are adopted as revised by this Treasury decision.

Explanation of Provisions

I. *Operating Mineral Interest Ownership Requirement*

The proposed regulations provide that only taxpayers with operating mineral interests may claim the section 43 credit. Commentators suggest that the operating mineral interest ownership requirement should be eliminated from the final regulations. Commentators argue that this provision creates substantial differences in the amount and the timing of the credit depending upon how a project is financed. For example, if a taxpayer constructs a pipeline to transport a tertiary injectant to the project site, the taxpayer would receive a front-end credit for the construction cost. On the other hand, if a taxpayer contracts to purchase the tertiary injectant from a supplier, who constructs a pipeline, the taxpayer would only receive the credit for the cost of the tertiary injectant when it is injected. Commentators indicate that the differential in the timing and the amount of the credit, depending upon how the project is financed, may determine whether a project is pursued.

Commentators further argue that the operating mineral interest ownership requirement places taxpayers who have alternative minimum tax liability, and thus are unable to use the credit, at a competitive disadvantage because they cannot sell or otherwise transfer the credit to a third party. Under this line of reasoning, taxpayers with alternative minimum tax liability would lack incentive to implement enhanced oil recovery projects.

Commentators suggest two alternatives to the operating mineral interest ownership requirement. First, commentators suggest that the final regulations provide for a credit-sharing arrangement whereby a taxpayer that does not own an operating mineral interest would be allowed to claim the credit if the taxpayer secures a certification from the operating mineral interest owners that they will not claim the credit for the same tangible property costs.

Second, commentators suggest a credit-sharing arrangement whereby the amount of the credit allowable to the owners of operating mineral interests would be reduced by the amount of the credit claimed by a taxpayer who pays or incurs costs in connection with the project, but does not own an operating mineral interest. This would be accomplished by requiring the owners of operating mineral interests to forgo claiming the credit with respect to certain costs up to the amount claimed by the taxpayer that does not own an operating mineral interest.

The credit-sharing arrangements suggested by the commentators were not adopted in the final regulations because of administrative difficulties. Allowing credit-sharing if the taxpayer secures a certification from the operating mineral interest owners that they will not claim the credit for the same tangible property costs would require a potentially difficult allocation to separate the capitalized costs of the tangible property from the market price of the tertiary injectants. Allowing credit-sharing arrangements whereby the credit allowable to owners of operating mineral interests is reduced by the amount of the credit claimed by a taxpayer who does not own an operating mineral interest would require detailed information-sharing between companies with the need to constantly update the data to reflect new expenditures. Because of these administrative difficulties with the proposed alternatives, the final regulations retain the requirement that a taxpayer claiming the credit must own an operating mineral interest.

II. *Significant Expansion -- Unaffected Acreage or Reservoir*

The proposed regulations provide that a project begun before January 1, 1991, is considered significantly expanded if it affects substantially unaffected acreage or a previously unaffected reservoir. Thus, under the proposed regulations, a lateral expansion would qualify for the credit; however, a vertical expansion would not qualify unless it affects a previously unaffected reservoir.

Commentators suggest that in lieu of the requirement that a significant expansion must affect substantially unaffected acreage or a previously unaffected reservoir, a project should be considered significantly expanded if it affects previously unaffected reservoir volume. Commentators indicate that the term "reservoir volume" more realistically reflects the three-dimensional concept petroleum engineers use in measuring reserves and the ultimate recovery of oil in place.

The final regulations reflect the comments and provide that a project is significantly expanded after December 31, 1990, if it affects reservoir volume that was substantially unaffected by a project begun before January 1, 1991.

III. *Significant Expansion -- More Than 36 Month Termination*

The proposed regulations provide that a project is considered significantly expanded if each tertiary recovery method implemented in a project prior to January 1, 1991, terminated more than 36 months before an enhanced oil recovery project commenced after December 31, 1990. This provision was intended to allow taxpayers to claim the credit for a project on property on which a prior project was terminated, while denying the opportunity to terminate and then restart an ongoing project for tax reasons.

Commentators suggest that in lieu of the requirement that a project be terminated for more than 36 months, a taxpayer should merely be required to demonstrate that the previous project was in fact terminated or that the second project is a new and distinct project that is being implemented to recover a more than insignificant amount of crude oil.

The final regulations are more flexible in regard to the 36-month termination rule. Although the 36-month rule is generally retained, a project that is terminated for less than 36 months may qualify for the credit if the taxpayer obtains permission from the Internal Revenue Service.

IV. *Significant Expansion -- Change in Method and More Intensive Application of a Method*

The proposed regulations provide that neither a change in tertiary recovery method nor a more intensive application of a method qualifies as a significant expansion. These rules were proposed to enhance the administrability of the significant expansion provisions.

Commentators suggest that rather than disqualifying a change in method or a more intensive application as a significant expansion, the final regulations should provide a facts and circumstances test to determine whether a project has been significantly expanded by a change in method or a more intensive application of a method. Some commentators suggest that a change in method should qualify as a significant expansion if it mobilizes previously immobile oil.

The final regulations reflect some of the commentators' suggestions. Under the final regulations, a taxpayer may qualify a change in method as a significant expansion by obtaining a private letter ruling. Whether a change in method qualifies as a significant expansion will be determined based on all the facts and circumstances. Among the factors that will be considered are whether the change in method is in accordance with sound engineering principles and whether the new method will result in a more than insignificant increase in the amount of crude oil that would be recovered under the previously applied method. The final regulations provide, however, that a more intensive application of a method is not considered to be a significant expansion.

V. *Qualified Tertiary Recovery Method*

The proposed regulations designate ten methods as qualified tertiary recovery methods and provide that the list of qualifying methods may be expanded only by revenue ruling. The proposed regulations specify that polymer augmented waterflooding does not include the injection of polymers for the purpose of modifying the injection profile of the wellbore (wellbore injection profile modification) rather than modifying the water-oil mobility ratio.

Commentators suggest that the final regulations should add four additional methods to the list of qualified methods described in the regulations: (1) Microbial enhanced oil recovery; (2) Mechanically and chemically enhanced waterflooding; (3) Vaporization of oil; and (4) Electromagnetic heating. Commentators argue that these methods are currently in commercial use and meet the general definition of a tertiary recovery method contained in the proposed regulations.

In addition, some commentators suggest that the final regulations should make clear that the costs of wellbore injection profile modification may be qualified costs if the wellbore injection modification is done in conjunction with a qualified method. These commentators suggest as well that profile modification techniques that affect the relative permeability of various layers of the reservoir (permeability modification), whether used alone or in conjunction with a qualified method, come within the definition of polymer augmented waterflooding.

Commentators also suggest that, in light of timeliness considerations, it would be more appropriate to qualify new methods by private letter ruling rather than by revenue ruling.

None of the methods suggested by the commentators have been added to the list of qualified methods because, although these methods may be applied in specialized circumstances, there is insufficient evidence regarding their general effectiveness. However, a project using one of these methods as part of a qualified method (*e.g.*, the injection of microbes into a reservoir to produce surfactants in a microemulsion flooding project) may qualify for the credit.

The final regulations reflect the commentators' suggestion that a project using wellbore injection profile modification or permeability modification in conjunction with a qualified method may qualify for the credit. However, wellbore injection profile modification and permeability profile modification alone are not tertiary recovery methods. Therefore, the final regulations make clear that injection profile modification and permeability modification do not come within the definition of polymer augmented waterflooding for purposes of section 43.

The final regulations are more flexible regarding how new methods are qualified. The final regulations retain the rule that new methods may be qualified by revenue ruling. In addition, however, a taxpayer may request a private letter ruling that a method, other than one of the listed methods or a method qualified by revenue ruling, is a qualified tertiary recovery method. The Internal Revenue Service intends to issue a revenue procedure prescribing guidelines for obtaining advance determinations.

VI. *Qualified Costs -- Primary Purpose and Allocation*

The proposed regulations provide that, as a general rule, an amount may be included in the credit base only if it is paid or incurred with respect to an asset that is used for the primary purpose of implementing a qualified enhanced oil recovery project. The proposed regulations require allocation of the costs of tangible property that is used for more than one qualified project and tangible property that is used for a qualified project and for other activities.

Commentators question whether the primary purpose rule is necessary in light of the proposed regulations' requirement that the cost of integral tangible property be allocated between qualifying and nonqualifying uses. Commentators state that the practical effect of the rule in the proposed regulations would be to deny the credit with respect to assets serving both a qualifying and nonqualifying project (i.e. a pre-existing project). Commentators argue that the primary purpose rule may be at odds with the realities of the oil industry. For example, the primary purpose rule does not take into account the fact that in isolated locations where geographic and climatic conditions impose high costs in the construction and transportation of facilities to the project site, operators attempt to combine multiple functions in a single facility to minimize capital and operating expenditures. Also an operator must drill a well that will be used in an enhanced oil recovery project when a drilling rig is available, without regard to whether enhanced oil recovery facilities are actually functioning or the injectant supply has arrived.

Commentators also express concern that the primary purpose rule would eliminate the costs of cogeneration facilities from the credit base. They argue that although a cogeneration facility produces electricity, the primary purpose of a cogeneration facility located on or near oil producing properties is to produce steam for the enhanced oil recovery project.

The final regulations modify the primary purpose rule contained in the proposed regulations in response to comments. Under the final regulations, a cost must be paid or incurred with respect to an asset used for the primary purpose of implementing one or more enhanced oil recovery projects, at least one of which must be a qualified enhanced oil recovery project. Accordingly, the rule does not deny the credit with respect to assets used primarily for tertiary recovery, but does deny the credit with respect to assets used primarily for secondary or primary recovery.

The final regulations retain the allocation requirement with two modifications. First, allocation is not required with respect to an asset with a *de minimis* nonqualifying use. Second, the allocation rule is applied with respect to the determination of all creditable costs under section 43. The allocation requirement is retained because the credit was intended to apply only to costs related to tertiary recovery. H. R. Rep. No. 964, 101st Cong., 2d Sess. 1124 (1990). The allocation requirement insures that costs related to primary or secondary recovery or to other activities unrelated to tertiary recovery are excluded from the credit base.

The final regulations recognize that some primary production may result when a well is drilled in connection with a qualified enhanced oil recovery project. Accordingly, the costs of drilling a well that is used for the primary purpose of implementing a qualified project are qualified costs notwithstanding that some primary or secondary recovery results, provided that the primary or secondary recovery is consistent with the qualified project plan.

The final regulations do not contain provisions specifically relating to cogeneration facilities. Depending upon the facts and circumstances, however, portions of a cogeneration facility may qualify for the credit under the primary purpose and allocation rules of the final regulations. A taxpayer wishing to claim the credit for costs associated with a cogeneration facility may request a private letter ruling regarding whether the costs are qualified costs.

VII. *Qualified Costs -- Tangible Property -- Placed in Service*

The proposed regulations provide that the cost of tangible property that is an integral part of a qualified enhanced oil recovery project is not included in the credit base until the property is placed in service in connection with the project. This provision is based on section 43(c)(1)(A)(ii), which provides that depreciation or amortization in lieu of depreciation must be allowable with respect to tangible property.

Commentaters argue that the credit should be allowed when costs are paid or incurred and should not be deferred until the property is placed in service. These comments contend that the requirement that depreciation or amortization be allowable with respect to the property is merely part of the definition of tangible property and not a timing requirement.

The final regulations adopt the analysis suggested in the comments and provide that tangible property costs are taken into account in determining the credit in the taxable year in which the costs are paid or incurred.

VIII. *Qualified Costs -- Tangible Property -- Integral Part*

The proposed regulations provide that tangible property is an integral part of a qualified enhanced oil recovery project if the property is used directly in a tertiary recovery method and is essential to the completeness of the method. The proposed regulations limit the credit to property actually used in the recovery of crude oil. Therefore, property that is used to store or process the produced oil (*e.g.*, storage tanks, gas processing plants, and refineries) is not eligible for the credit.

Commentaters suggest the definition of "integral part" should focus on whether property is used directly in or is essential to the completeness of the project rather than the method. Commentaters also suggest that the final regulations contain examples that: (1) Treat the cost of leasing tangible property as qualified cost; (2) specify that oil storage tanks are an integral part of a project; and (3) distinguish between gas processing equipment and equipment that is used in the recycling of tertiary injectants.

The final regulations generally adopt the suggestions made in the comments, and accordingly, provide that the integral part test is determined with respect to the project, not the method. However, the final regulations adopt the position of the proposed regulations by excluding the costs of storage tanks from the credit base. There must be a cutoff point for the credit somewhere between production and distribution of the oil, and storage facilities are a reasonable place to draw the line.

IX. *Pre-injection Costs*

The proposed regulations provide that costs may be taken into account in determining the amount of the credit only after first injection occurs. If first injection occurs on or before the date the taxpayer files a return for the year the credit is allowable for the costs, the taxpayer may claim the credit for the costs on the return. However, if first injection occurs after the return is filed, the taxpayer may claim the credit on an amended return for the year the credit is allowable for the costs. If first injection occurs more than 36 months after the close of the taxable year in which the costs are paid or incurred, the costs may not be taken into account in determining the credit for any taxable year.

Commentators argue that deferring the credit until first injection has occurred penalizes both large-scale projects that require lengthy construction periods and operations with limited transportation opportunities. Commentators suggest that the 36-month limitation on claiming the credit for pre-injection costs should be eliminated or that the pre-injection "window" should be widened from 36 months to 48 months to take into account operational and technical parameters.

In response to the comments, the final regulations are more flexible in regard to costs paid or incurred prior to first injection. As in the proposed regulations, if first injection occurs on or before the date a taxpayer files a federal income tax return for the taxable year in which the costs are paid or incurred (the initial return), the costs may be taken into account on that return; and if first injection occurs later, the costs may be taken into account on an amended return. The final regulations add that if first injection occurs or is expected to occur after the initial return is filed (including at a time that is more than 36 months after the close of the taxable year in which the costs are paid or incurred), the taxpayer may include the costs in the credit base on a return filed before first injection if a private letter ruling is obtained.

X. *Certification*

Section 1.43-3T of the temporary regulations relating to the certification of enhanced oil recovery projects is adopted in these final regulations. However, the contents of a significant expansion certification are changed to reflect the significant expansion provisions in the final regulations.

Special Analyses

These rules are not major rules as defined in Executive Order 12291. Therefore, a Regulatory Impact Analysis is not required. Although this Treasury decision was preceded by a notice of proposed rulemaking that solicited public comments, the notice was not required by *5 U.S.C. 553* since the regulations proposed in that notice and adopted by this Treasury decision are interpretative. Therefore, a final Regulatory Flexibility Analysis is not required by the Regulatory Flexibility Act *(5 U.S.C. chapter 6).*

Drafting Information

The principal author of these regulations is Brenda M. Stewart of the Office of Assistant Chief Counsel (Passthroughs and Special Industries), Internal Revenue Service. However, personnel from other offices of the Internal Revenue Service and Treasury Department participated in developing the regulations, both on matters of substance and style.

List of Subjects

26 CFR 1.28-0 through 1.44A-4

Credits, Drugs, Income taxes, Reporting and recordkeeping requirements.

26 CFR Part 602

Reporting and recordkeeping requirements.

Adoption of Amendments to Regulations

Accordingly, title 26, chapter 1, parts 1 and 602, of the Code of Federal Regulations is amended as follows:

PART 1 -- INCOME TAX; TAXABLE YEARS BEGINNING AFTER DECEMBER 31, 1953

Paragraph. 1. The authority for part 1 is amended by adding the following citation:

Authority: *26 U.S.C. 7805* * * * Sections 1.43-0 through 1.43-7 also issued under section *26 U.S.C. 43.*

Par. 2. Sections 1.43-1 and 1.43-2 are redesignated as §§ 32-1 and 1.32-2 and new §§ 43-0 through 1.43-2 are added to read as set forth below:

§ 1.43-0 Table of contents.

This section lists the captions contained in §§ 1.43-0 through 1.43-7.

§ 1.43-1 The enhanced oil recovery credit -- general rules.

(a) Claiming the credit.

(1) In general.

(2) Examples.

(b) Amount of the credit.

(c) Phase-out of the credit as crude oil prices increase.

(1) In general.

(2) Inflation adjustment.

(3) Examples.

(d) Reduction of associated deductions.

(1) In general.

(2) Certain deductions by an integrated oil company.

(e) Basis adjustment.

(f) Passthrough entity basis adjustment.

(1) Partners' interests in a partnership.

(2) Shareholders' stock in an S corporation.

(g) Examples.

§ 1.43-2 Qualified enhanced oil recovery project.

(a) Qualified enhanced oil recovery project.

(b) More than insignificant increase.

(c) First injection of liquids, gases, or other matter.

(1) In general.

(2) Example.

(d) Significant expansion exception.

(1) In general.

(2) Substantially unaffected reservoir volume.

(3) Terminated projects.

(4) Change in tertiary recovery method.

(5) Examples.

(e) Qualified tertiary recovery methods.

(1) In general.

(2) Tertiary recovery methods that qualify.

(3) Recovery methods that do not qualify.

(4) Examples.

§ 1.43-3 Certification.

(a) Petroleum engineer's certification of a project.

(1) In general.

(2) Timing of certification.

(3) Content of certification.

(b) Operator's continued certification of a project.

(1) In general.

(2) Timing of certification.

(3) Content of certification.

(c) Notice of project termination.

(1) In general.

(2) Timing of notice.

(3) Content of notice.

(d) Failure to submit certification.

(e) Effective date.

§ 1.43-4 Qualified enhanced oil recovery costs.

(a) Qualifying costs.

(1) In general.

(2) Costs paid or incurred for an asset which is used to implement more than one qualified enhanced oil recovery project or for other activities.

(b) Costs defined.

(1) Qualified tertiary injectant expenses.

(2) Intangible drilling and development costs.

(3) Tangible property costs.

(4) Examples.

(c) Primary purpose.

(1) In general.

(2) Tertiary injectant costs.

(3) Intangible drilling and development costs.

(4) Tangible property costs.

(5) Offshore drilling platforms.

(6) Examples.

(d) Costs paid or incurred prior to first injection.

(1) In general.

(2) First injection after filing of return for taxable year costs are allowable.

(3) First injection more than 36 months after close of taxable year costs are paid or incurred.

(4) Injections in volumes less than the volumes specified in the project plan.

(5) Examples.

(e) Other rules.

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(1) Anti-abuse rule.

(2) Costs paid or incurred to acquire a project.

(3) Examples.

§ 1.43-5 At-risk limitation. [Reserved]

§ 1.43-6 Election out of section 43.

(a) Election to have the credit not apply.

(1) In general.

(2) Time for making the election.

(3) Manner of making the election.

(b) Election by partnerships and S corporations.

§ 1.43-7 Effective date of regulations.

§ 1.43-1 The enhanced oil recovery credit -- general rules.

(a) *Claiming the credit* -- (1) *In general.* The enhanced oil recovery credit (the "credit") is a component of the section 38 general business credit. A taxpayer that owns an operating mineral interest (as defined in § 1.614-2(b)) in a property may claim the credit for qualified enhanced oil recovery costs (as described in § 1.43-4) paid or incurred by the taxpayer in connection with a qualified enhanced oil recovery project (as described in § 1.43-2) undertaken with respect to the property. A taxpayer that does not own an operating mineral interest in a property may not claim the credit. To the extent a credit included in the current year business credit under section 38(b) is unused under section 38, the credit is carried back or forward under the section 39 business credit carryback and carryforward rules.

(2) *Examples.* The following examples illustrate the principles of this paragraph (a).

Example 1. Credit for operating mineral interest owner. In 1992, A, the owner of an operating mineral interest in a property, begins a qualified enhanced oil recovery project using cyclic steam. B, who owns no interest in the property, purchases and places in service a steam generator. B sells A steam, which A uses as a tertiary injectant described in section 193. Because A owns an operating mineral interest in the property with respect to which the project is undertaken, A may claim a credit for the cost of the steam. Although B owns the steam generator used to produce steam for the project, B may not claim a credit for B's costs because B does not own an operating mineral interest in the property.

Example 2. Credit for operating mineral interest owner. C and D are partners in CD, a partnership that owns an operating mineral interest in a property. In 1992, CD begins a qualified enhanced oil recovery project using cyclic steam. D purchases a steam generator and sells steam to CD. Because CD owns an operating mineral interest in the property with respect to which the project is undertaken, CD may claim a credit for the cost of the steam. Although D owns the steam generator used to produce steam for the project, D may not claim a credit for the cost of the steam generator because D paid these costs in a capacity other than that of an operating mineral interest owner.

(b) *Amount of the credit.* A taxpayer's credit is an amount equal to 15 percent of the taxpayer's qualified enhanced oil recovery costs for the taxable year, reduced by the phase-out amount, if any, determined under paragraph (c) of this section.

(c) *Phase-out of the credit as crude oil prices increase* -- (1) *In general.* The amount of the credit (determined without regard to this paragraph (c)) for any taxable year is reduced by an amount which bears the same ratio to the amount of the credit (determined without regard to this paragraph (c)) as --

(i) The amount by which the reference price determined under section 29(d)(2)(C) for the calendar year immediately preceding the calendar year in which the taxable year begins exceeds $28 (as adjusted under paragraph (c)(2) of this section); bears to

(ii) $6.

(2) *Inflation adjustment* -- (i) *In general.* For any taxable year beginning in a calendar year after 1991, an amount equal to $28 multiplied by the inflation adjustment factor is substituted for the $28 amount under paragraph (c)(1)(i) of this section.

(ii) *Inflation adjustment factor.* For purposes of this paragraph (c), the inflation adjustment factor for any calendar year is a fraction, the numerator of which is the GNP implicit price deflator for the preceding calendar year and the denominator of which is the GNP implicit price deflator for 1990. The "GNP implicit price deflator" is the first revision of the implicit price deflator for the gross national product as computed and published by the Secretary of Commerce. As early as practicable, the inflation adjustment factor for each calendar year will be published by the Internal Revenue Service in the Internal Revenue Bulletin.

(3) *Examples.* The following examples illustrate the principles of this paragraph (c).

Example 1. Reference price exceeds $28. In 1992, E, the owner of an operating mineral interest in a property, incurs $100 of qualified enhanced oil recovery costs. The reference price for 1991 determined under section 29(d)(2)(C) is $30 and the inflation adjustment factor for 1992 is 1. E's credit for 1992 determined without regard to the phase-out for crude oil price increases is $15 ($100 X 15%). In determining E's credit, the credit is reduced by $5 ($15 X ($30 - ($28 X 1))/6). Accordingly, E's credit for 1992 is $10 ($15 - $5).

Example 2. Inflation adjustment. In 1993, F, the owner of an operating mineral interest in a property, incurs $100 of qualified enhanced oil recovery costs. The 1992 reference price is $34, and the 1993 inflation adjustment factor is 1.10. F's credit for 1993 determined without regard to the phase-out for crude oil price increases is $15 ($100 X 15%). In determining F's credit, $30.80 (1.10 X $28) is substituted for $28, and the credit is reduced by $8 ($15 X ($34 - $30.80)/6). Accordingly, F's credit for 1993 is $7 ($15 - $8).

(d) *Reduction of associated deductions* -- (1) *In general.* Any deduction allowable under chapter 1 for an expenditure taken into account in computing the amount of the credit determined under paragraph (b) of this section is reduced by the amount of the credit attributable to the expenditure.

(2) *Certain deductions by an integrated oil company.* For purposes of determining the intangible drilling and development costs that an integrated oil company must capitalize under section 291(b), the amount allowable as a deduction under section 263(c) is the deduction allowable after paragraph (d)(1) of this section is applied. See § 1.43-4(b)(2) (extent to which integrated oil company intangible drilling and development costs are qualified enhanced oil recovery costs).

(e) *Basis adjustment.* For purposes of subtitle A, the increase in the basis of property which would (but for this paragraph (e)) result from an expenditure with respect to the property is reduced by the amount of the credit determined under paragraph (b) of this section attributable to the expenditure.

(f) *Passthrough entity basis adjustment* -- (1) *Partners' interests in a partnership.* To the extent a partnership expenditure is not deductible under paragraph (d)(1) of this section or does not increase the basis of property under paragraph (e) of this section, the expenditure is treated as an expenditure described in section 705(a)(2)(B) (concerning decreases to basis of partnership interests). Thus, the adjusted bases of the partners' interests in the partnership are decreased (but not below zero).

(2) *Shareholders' stock in an S corporation.* To the extent an S corporation expenditure is not deductible under paragraph (d)(1) of this section or does not increase the basis of property under paragraph (e) of this section, the expenditure is treated as an expenditure described in section 1367(a)(2)(D) (concerning decreases to basis of S corporation stock). Thus, the bases of the shareholders' S corporation stock are decreased (but not below zero).

(g) *Examples.* The following examples illustrate the principles of paragraphs (d) through (f) of this section.

Example 1. Deductions reduced for credit amount. In 1992, G, the owner of an operating mineral interest in a property, incurs $100 of intangible drilling and development costs in connection with a qualified enhanced oil recovery project undertaken with respect to the property. G elects under section 263(c) to deduct these intangible drilling and development costs under section 263(c). The amount of the credit determined under paragraph (b) of this section attributable to the $100 of intangible drilling and development costs is $15 ($100 X 15%). Therefore, G's otherwise allowable deduction of $100 for the intangible drilling and development costs is reduced by $15. Accordingly, in 1992, G may deduct under section 263(c) only $85 ($100 - $15) for these costs.

Example 2. Integrated oil company deduction reduced. The facts are the same as in *Example 1,* except that G is an integrated oil company. As in *Example 1,* the amount of the credit determined under paragraph (b) of this section attributable to the $100 of intangible drilling and development costs is $15, and G's allowable deduction under section 263(c) is $85. Because G is an integrated oil company, G must capitalize 25.50 ($85 X 30%) under section 291(b). Therefore, in 1992, G may deduct under section 263(c) only $59.50 ($85 - $25.50) for these intangible drilling and development costs.

Example 3. Basis of property reduced. In 1992, H, the owner of an operating mineral interest in a property, pays $100 to purchase tangible property that is an integral part of a qualified enhanced oil recovery project undertaken with respect to the property. The amount of the credit determined under paragraph (b) of this section attributable to the $100 is $15 ($100 X 15%). Therefore, for purposes of subtitle A, H's basis in the tangible property is $85 ($100 - $15).

Example 4. Basis of interest in passthrough entity reduced. In 1992, I is a $50% partner in IJ, a partnership that owns an operating mineral interest in a property. IJ pays $200 to purchase tangible property that is an integral part of a qualified enhanced oil recovery project undertaken with respect to the property. The amount of the credit determined under paragraph (b) of this section attributable to the $200 is $30 ($200 X 15%). Therefore, for purposes of subtitle A, IJ's basis in the tangible property is $170 ($200 - $30). Under paragraph (f) of this section, the amount of the purchase price that does not increase the basis of the property ($30) is treated as an expenditure described in section 705(a)(2)(B). Therefore, I's basis in the partnership interest is reduced by $15 (I's allocable share of the section 705(a)(2)(B) expenditure ($30 X 50%)).

§ 1.43-2 Qualified enhanced oil recovery project.

(a) *Qualified enhanced oil recovery project.* A "qualified enhanced oil recovery project" is any project that meets all of the following requirements --

(1) The project involves the application (in accordance with sound engineering principles) of one or more qualified tertiary recovery methods (as described in paragraph (e) of this section) that is reasonably expected to result in more than an insignificant increase in the amount of crude oil that ultimately will be recovered;

(2) The project is located within the United States (within the meaning of section 638(1));

(3) The first injection of liquids, gases, or other matter for the project (as described in paragraph (c) of this section) occurs after December 31, 1990; and

(4) The project is certified under § 1.43-3.

(b) *More than insignificant increase.* For purposes of paragraph (a)(1) of this section, all the facts and circumstances determine whether the application of a tertiary recovery method can reasonably be expected to result in more than an insignificant increase in the amount of crude oil that ultimately will be recovered. Certain information submitted as part of a project certification is relevant to this determination. See § 1.43-3(a)(3)(i)(D). In no event is the application of a recovery method that merely accelerates the recovery of crude oil considered an application of one or more qualified tertiary recovery methods that can reasonably be expected to result in more than an insignificant increase in the amount of crude oil that ultimately will be recovered.

(c) *First injection of liquids, gases, or other matter* -- (1) *In general.* The "first injection of liquids, gases, or other matter" generally occurs on the date a tertiary injectant is first injected into the reservoir. The "first injection of liquids, gases, or other matter" does not include --

(i) The injection into the reservoir of any liquids, gases, or other matter for the purpose of pretreating or preflushing the reservoir to enhance the efficiency of the tertiary recovery method; or

(ii) Test or experimental injections.

(2) *Example.* The following example illustrates the principles of this paragraph (c).

Example. Injections to pretreat the reservoir. In 1989, A, the owner of an operating mineral interest in a property, began injecting water into the reservoir for the purpose of elevating reservoir pressure to obtain miscibility pressure to prepare for the injection of miscible gas in connection with an enhanced oil recovery project. In 1992, A obtains miscibility pressure in the reservoir and begins injecting miscible gas into the reservoir. The injection of miscible gas, rather than the injection of water, is the first injection of liquids, gases, or other matter into the reservoir for purposes of determining whether the first injection of liquids, gases, or other matter occurs after December 31, 1990.

(d) *Significant expansion exception* -- (1) *In general.* If a project for which the first injection of liquids, gases, or other matter (within the meaning of paragraph (c)(1) of this section) 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.

(2) *Substantially unaffected reservoir volume.* A project is considered significantly expanded if the injection of liquids, gases, or other matter after December 31, 1990, is reasonably expected to result in more than an insignificant increase in the amount of crude oil that ultimately will be recovered from reservoir volume that was substantially unaffected by the injection of liquids, gases, or other matter before January 1, 1991.

(3) *Terminated projects.* Except as otherwise provided in this paragraph (d)(3), a project is considered significantly expanded if each qualified tertiary recovery method implemented in the project prior to January 1, 1991, terminated more than 36 months before implementing an enhanced oil recovery project that commences after December 31, 1990. Notwithstanding the provisions of the preceding sentence, if a project implemented prior to January 1, 1991, is terminated for less than 36 months before implementing an enhanced oil recovery project that commences after December 31, 1990, a taxpayer may request permission to treat the project that commences after December 31, 1990, as a significant expansion. Permission will not be granted if the Internal Revenue Service determines that a project was terminated to make an otherwise nonqualifying project eligible for the credit. For purposes of section 43, a qualified tertiary recovery method terminates at the point in time when the method no longer results in more than an insignificant increase in the amount of crude oil that ultimately will be recovered. All the facts and circumstances determine whether a tertiary recovery method has terminated. Among the factors considered is the project plan, the unit plan of

development, or other similar plan. A tertiary recovery method is not necessarily terminated merely because the injection of the tertiary injectant has ceased. For purposes of this paragraph (d)(1), a project is implemented when costs that will be taken into account in determining the credit with respect to the project are paid or incurred.

(4) *Change in tertiary recovery method.* If the application of a tertiary recovery method or methods with respect to an enhanced oil recovery project for which the first injection of liquids, gases, or other matter occurred before January 1, 1991, has not been terminated for more than 36 months, a taxpayer may request a private letter ruling from the Internal Revenue Service whether the application of a different tertiary recovery method or methods after December 31, 1990, that does not affect reservoir volume substantially unaffected by the previous tertiary recovery method or methods, is treated as a significant expansion. All the facts and circumstances determine whether a change in tertiary recovery method is treated as a significant expansion. Among the factors considered are whether the change in tertiary recovery method is in accordance with sound engineering principles and whether the change in method will result in more than an insignificant increase in the amount of crude oil that would be recovered using the previous method. A more intensive application of a tertiary recovery method after December 31, 1990, is not treated as a significant expansion.

(5) *Examples.* The following examples illustrate the principles of this paragraph (d).

Example 1. Substantially unaffected reservoir volume. In January 1988, B, the owner of an operating mineral interest in a property, began injecting steam into the reservoir in connection with a cyclic steam enhanced oil recovery project. The project affected only a portion of the reservoir volume. In 1992, B begins cyclic steam injections with respect to reservoir volume that was substantially unaffected by the previous cyclic steam project. Because the injection of steam into the reservoir in 1992 affects reservoir volume that was substantially unaffected by the previous cyclic steam injection, the cyclic steam injection in 1992 is treated as a separate project for which the first injection of liquids, gases, or other matter occurs after December 31, 1990.

Example 2. Tertiary recovery method terminated more than 36 months. In 1982, C, the owner of an operating mineral interest in a property, implemented a tertiary recovery project using cyclic steam injection as a method for the recovery of crude oil. The project was certified as a tertiary recovery project for purposes of the windfall profit tax. In May 1988, the application of the cyclic steam tertiary recovery method terminated. In July 1992, C begins drilling injection wells as part of a project to apply the steam drive tertiary recovery method with respect to the same project area affected by the cyclic steam method. C begins steam injections in September 1992. Because C commences an enhanced oil recovery project more than 36 months after the previous tertiary recovery method was terminated, the project is treated as a separate project for which the first injection of liquids, gases, or other matter occurs after December 31, 1990.

Example 3. Change in tertiary recovery method affecting substantially unaffected reservoir volume. In 1984, D, the owner of an operating mineral interest in a property, implemented a tertiary recovery project using cyclic steam as a method for the recovery of crude oil. The project was certified as a tertiary recovery project for purposes of the windfall profit tax. D continued the cyclic steam injection until 1992, when the tertiary recovery method was changed from cyclic steam injection to steam drive. The steam drive affects reservoir volume that was substantially unaffected by the cyclic steam injection. Because the steam drive affects reservoir volume that was substantially unaffected by the cyclic steam injection, the steam drive is treated as a separate project for which the first injection of liquids, gases, or other matter occurs after December 31, 1990.

Example 4. Change in tertiary recovery method not affecting substantially unaffected reservoir volume. In 1988, E, the owner of an operating mineral interest in a property, undertook an immiscible nitrogen enhanced oil recovery project that resulted in more than an insignificant increase in the ultimate recovery of crude oil from the property. E continued the immiscible nitrogen project until 1992, when the project was converted from immiscible nitrogen displacement to miscible nitrogen displacement by increasing the injection of nitrogen to increase reservoir pressure. The miscible nitrogen displacement affects the same reservoir volume that was affected by the immiscible nitrogen displacement. Because the miscible nitrogen displacement does not affect reservoir volume that was substantially unaffected by the immiscible nitrogen displacement nor was the immiscible nitrogen displacement project terminated for more than 36 months before the miscible nitrogen displacement project was implemented, E must obtain a ruling whether the change from immiscible nitrogen displacement to miscible nitrogen displacement is treated as a separate project for which the first injection of liquids, gases, or other matter occurs after December 31, 1990. If E does not receive a ruling, the miscible nitrogen displacement project is not a qualified project.

Example 5. More intensive application of a tertiary recovery method. In 1989, F, the owner of an operating mineral interest in a property, undertook an immiscible carbon dioxide displacement enhanced oil recovery project. F began injecting carbon dioxide into the reservoir under immiscible conditions. The injection of carbon dioxide under immiscible conditions resulted in more than an insignificant increase in the ultimate recovery of crude oil from the property. F continues to inject the same amount of carbon dioxide into the reservoir until 1992, when new engineering studies indicate that an increase in the amount of carbon dioxide injected is reasonably expected to result in a more than insignificant increase in the amount of crude oil that would be recovered from the property as a result of the previous injection of carbon dioxide. The increase in the amount of carbon dioxide injected affects the same reservoir volume that was affected by the previous injection of carbon dioxide. Because the additional carbon dioxide injected in 1992 does not affect reservoir volume that was substantially unaffected by the previous injection of carbon dioxide and the previous immiscible carbon dioxide displacement method was not terminated for more than 36 months before additional carbon dioxide was injected, the increase in the amount of carbon dioxide injected into the reservoir is not a significant expansion. Therefore, it is not a separate project for which the first injection of liquids, gases, or other matter occurs after December 31, 1990.

(e) *Qualified tertiary recovery methods* -- (1) *In general.* For purposes of paragraph (a)(1) of this section, a "qualified tertiary recovery method" is any one or any combination of the tertiary recovery methods described in paragraph (e)(2) of this section. To account for advances in enhanced oil recovery technology, the Internal Revenue Service may by revenue ruling prescribe that a method not described in paragraph (e)(2) of this section is a "qualified tertiary recovery method." In addition, a taxpayer may request a private letter ruling that a method not described in paragraph (e)(2) of this section or in a revenue ruling is a qualified tertiary recovery method. Generally, the methods identified in revenue rulings or private letter rulings will be limited to those methods that involve the displacement of oil from the reservoir rock by means of modifying the properties of the fluids in the reservoir or providing the energy and drive mechanism to force the oil to flow to a production well. The recovery methods described in paragraph (e)(3) of this section are not "qualified tertiary recovery methods."

(2) *Tertiary recovery methods that qualify* -- (1) *Thermal recovery methods* -- (A) *Steam drive injection.* The continuous injection of steam into one set of wells (injection wells) or other injection source to effect oil displacement toward and production from a second set of wells (production wells);

(B) *Cyclic steam injection* -- The alternating injection of steam and production of oil with condensed steam from the same well or wells; and

(C) *In situ combustion.* The combustion of oil or fuel in the reservoir sustained by injection of air, oxygen-enriched air, oxygen, or supplemental fuel supplied from the surface to displace unburned oil toward producing wells. This process may include the concurrent, alternating, or subsequent injection of water.

(ii) *Gas Flood recovery methods* -- (A) *Miscible fluid displacement.* The injection of gas (*e.g.,* natural gas, enriched natural gas, a liquified petroleum slug driven by natural gas, carbon dioxide, nitrogen, or flue gas) or alcohol into the reservoir at pressure levels such that the gas or alcohol and reservoir oil are miscible;

(b) *Carbon dioxide augmented waterflooding.* The injection of carbonated water, or water and carbon dioxide, to increase waterflood efficiency;

(C) *Immiscible carbon dioxide displacement.* The injection of carbon dioxide into an oil reservoir to effect oil displacement under conditions in which miscibility with reservoir oil is not obtained. This process may include the concurrent, alternating, or subsequent injection of water; and

(D) *Immiscible nonhydrocarbon gas displacement.* The injection of nonhydrocarbon gas (*e.g.,* nitrogen) into an oil reservoir, under conditions in which miscibility with reservoir oil is not obtained, to obtain a chemical or physical reaction (other than pressure) between the oil and the injected gas or between the oil and other reservoir fluids. This process may include the concurrent, alternating, or subsequent injection of water.

(iii) *Chemical flood recovery methods* -- (A) *Microemulsion flooding.* The injection of a surfactant system *e.g.,* a surfactant, hydrocarbon, cosurfactant, electrolyte, and water) to enhance the displacement of oil toward producing wells; and

(B) *Caustic flooding* -- The injection of water that has been made chemically basic by the addition of alkali metal hydroxides, silicates, or other chemicals.

(iv) *Mobility control recovery method* -- *Polymer augmented waterflooding.* The injection of polymeric additives with water to improve the areal and vertical sweep efficiency of the reservoir by increasing the viscosity and decreasing the mobility of the water injected. Polymer augmented waterflooding does not include the injection of polymers for the purpose of modifying the injection profile of the wellbore or the relative permeability of various layers of the reservoir, rather than modifying the water-oil mobility ratio.

(3) *Recovery methods that do not qualify.* The term "qualified tertiary recovery method" does not include --

(i) Waterflooding -- The injection of water into an oil reservoir to displace oil from the reservoir rock and into the bore of the producing well;

(ii) Cyclic gas injection -- The increase or maintenance of pressure by injection of hydrocarbon gas into the reservoir from which it was originally produced;

(iii) Horizontal drilling -- The drilling of horizontal, rather than vertical, wells to penetrate hydrocarbon bearing formations;

(iv) Gravity drainage -- The production of oil by gravity flow from drainholes that are drilled from a shaft or tunnel dug within or below the oil bearing zones; and

(v) Other methods -- Any recovery method not specifically designated as a qualified tertiary recovery method in either paragraph (e)(2) of this section or in a revenue ruling or private letter ruling described in paragraph (e)(1) of this section.

(4) *Examples.* The following examples illustrate the principles of this paragraph (e).

Example 1. Polymer augmented waterflooding. In 1992 G, the owner of an operating mineral interest in a property, begins a waterflood project with respect to the property. To reduce the relative permeability in certain areas of the reservoir and minimize water coning, G injects polymers to plug thief zones and improve the areal and vertical sweep efficiency of the reservoir. The injection of polymers into the reservoir does not modify the water-oil mobility ratio. Accordingly, the injection of polymers into the reservoir in connection with the waterflood project does not constitute polymer augmented waterflooding and the project is not a qualified enhanced oil recovery project.

Example 2. Polymer augmented waterflooding. In 1993 H, the owner of an operating mineral interest in a property, begins a caustic flooding project with respect to the property. Engineering studies indicate that the relative permeability of various layers of the reservoir may result in the loss of the injectant to thief zones, thereby reducing the areal and vertical sweep efficiency of the reservoir. As part of the caustic flooding project, H injects polymers to plug the thief zones and improve the areal and vertical sweep efficiency of the reservoir. Because the polymers are injected into the reservoir to improve the effectiveness of the caustic flooding project, the project is a qualified enhanced oil recovery project.

§ 1.43-3T [Redesignated as § 1.43-3]

Par. 3.

Section 1.43-3T is redesignated as § 1.43-3 and is amended as follows:

1. The section heading is amended by removing the word "(Temporary)".

2. Paragraph (a)(3)(i)(C)(*1*) is amended by removing the word "and" at the end of that paragraph and adding in its place ";".

3. Paragraph (a)(3)(i)(C)(*2*) is redesignated as paragraph (a)(3)(i)(C)(*3*) and is amended by removing ";" and adding in its place ".".

4. New paragraph (a)(3)(i)(C)(*2*) is added to read as set forth below.

5. Paragraph (a)(3)(ii)(A) is revised to read as set forth below.

6. Paragraph (a)(3)(ii)(B) is removed.

7. Paragraph (a)(3)(ii)(C) is redesignated as paragraph (a)(3)(ii)(B) and is amended by removing "." and adding in its place ";".

8. New paragraphs (a)(3)(ii) (C) and (D) are added to read as set forth below.

9. Paragraph (e) is removed.

§ 1.43-3 Certification.

(a) * * *

(3) * * *

(i) * * *

(C) * * *

(*2*) If the project involves the application of a tertiary recovery method approved in a private letter ruling described in paragraph (e)(1) of § 1.43-2, a copy of the private letter ruling, and

(ii) * * *

(A) If the expansion affects reservoir volume that was substantially unaffected by a previously implemented project, an adequate delineation of the reservoir volume affected by the previously implemented project;

* * * * *

(C) If the expansion involves the implementation of an enhanced oil recovery project less than 36 months after the termination of a qualified tertiary recovery method that was applied before January 1, 1991, a copy of a private letter ruling from the Internal Revenue Service that the project implemented after December 31, 1990 is treated as a significant expansion; or

(D) If the expansion involves the application after December 31, 1990, of a tertiary recovery method or methods that do not affect reservoir volume that was substantially unaffected by the application of a different tertiary recovery method or methods before January 1, 1991, a copy of a private letter ruling from the Internal Revenue Service that the change in tertiary recovery method is treated as a significant expansion.

* * * * *

Par. 4. Sections 1.43-4, 1.43-6 and 1.43-7 are added and § 1.43-5 is added and reserved as set forth below:

§ 1.43-4 Qualified enhanced oil recovery costs.

(a) *Qualifying costs* -- (1) *In general.* Except as provided in paragraph (e) of this section, amounts paid or incurred in any taxable year beginning after December 31, 1990, that are qualified tertiary injectant expenses (as described in paragraph (b)(1) of this section), intangible drilling and development costs (as described in paragraph (b)(2) of this section), and tangible property costs (as described in paragraph (b)(3) of this section) are "qualified enhanced oil recovery costs" if the amounts are paid or incurred with respect to an asset which is used for the primary purpose (as described in paragraph (c) of this section) of implementing an enhanced oil recovery project. Any amount paid or incurred in any taxable year beginning before January 1, 1991, in connection with an enhanced oil recovery project is not a qualified enhanced oil recovery cost.

(2) *Costs paid or incurred for an asset which is used to implement more than one qualified enhanced oil recovery project or for other activities.* Any cost paid or incurred during the taxable year for an asset which is used to implement more than one qualified enhanced oil recovery project is allocated among the projects in determining the qualified enhanced oil recovery costs for each qualified project for the taxable year. Similarly, any cost paid or incurred during the taxable year for an asset which is used to implement a qualified enhanced oil recovery project and which is also used for other activities (for example, an enhanced oil recovery project that is not a qualified enhanced oil recovery project) is allocated among the qualified enhanced oil recovery project and the other activities to determine the qualified enhanced oil recovery costs for the taxable year. See § 1.613-5(a). Any cost paid or incurred for an asset which is used to implement a qualified enhanced oil recovery project and which is also used for other activities is not required to be allocated under this paragraph (a)(2) if the use of the property for nonqualifying activities is *de minimis* (*e.g.*, not greater than 10%). Costs are allocated under this paragraph (a)(2) only if the asset with respect to which the costs are paid or incurred is used for the primary purpose of implementing an enhanced oil recovery project. *See* paragraph (c) of this section. Any reasonable allocation method may be used. A method that allocates costs based on the anticipated use in a project or activity is a reasonable method.

(b) *Costs defined* -- (1) *Qualified tertiary injectant expenses.* For purposes of this section, "qualified tertiary injectant expenses" means any costs that are paid or incurred in connection with a qualified enhanced oil recovery project and that are deductible under section 193 for the taxable year. *See* section 193 and § 1.193-1. Qualified tertiary injectant expenses are taken into account in determining the credit with respect to the taxable year in which the tertiary injectant expenses are deductible under section 193.

(2) *Intangible drilling and development costs.* For purposes of this section, "intangible drilling and development costs" means any intangible drilling and development costs that are paid or incurred in connection with a qualified enhanced oil recovery project and for which the taxpayer may make an election under section 263(c) for the taxable year. Intangible drilling and development costs are taken into account in determining the credit with respect to the taxable year in which the taxpayer may deduct the intangible drilling and development costs under section 263(c). For

purposes of this paragraph (b)(2), the amount of the intangible drilling and development costs for which an integrated oil company may make an election under section 263(c) is determined without regard to section 291(b).

(3) *Tangible property costs* -- (i) *In general.* For purposes of this section, "tangible property costs" means an amount paid or incurred during a taxable year for tangible property that is an integral part of a qualified enhanced oil recovery project and that is depreciable or amortizable under chapter 1. An amount paid or incurred for tangible property is taken into account in determining the credit with respect to the taxable year in which the cost is paid or incurred.

(ii) *Integral part.* For purposes of this paragraph (b), tangible property is an integral part of a qualified enhanced oil recovery project if the property is used directly in the project and is essential to the completeness of the project. All the facts and circumstances determine whether tangible property is used directly in a qualified enhanced oil recovery project and is essential to the completeness of the project. Generally, property used to acquire or produce the tertiary injectant or property used to transport the tertiary injectant to a project site is property that is an integral part of the project.

(4) *Examples.* The following examples illustrate the principles of this paragraph (b). Assume for each of these examples that the qualified enhanced oil recovery costs are paid or incurred with respect to an asset which is used for the primary purpose of implementing an enhanced oil recovery project.

Example 1. Qualified costs -- in general. (i) In 1992, X, a corporation, acquires an operating mineral interest in a property and undertakes a cyclic steam enhanced oil recovery project with respect to the property. X pays a fee to acquire a permit to drill and hires a contractor to drill six wells. As part of the project implementation, X constructs a building to serve as an office on the property and purchases equipment, including downhole equipment (*e.g.*, casing, tubing, packers, and sucker rods), pumping units, a steam generator, and equipment to remove gas and water from the oil after it is produced. X constructs roads to transport the equipment to the wellsites and incurs costs for clearing and draining the ground in preparation for the drilling of the wells. X purchases cars and trucks to provide transportation for monitoring the wellsites. In addition, X contracts with Y for the delivery of water to produce steam to be injected in connection with the cyclic steam project, and purchases storage tanks to store the water.

(ii) The leasehold acquisition costs are not qualified enhanced oil recovery costs. However, the costs of the permit to drill are intangible drilling and development costs that are qualified costs. The costs associated with hiring the contractor to drill, constructing roads, and clearing and draining the ground are intangible drilling and development costs that are qualified enhanced oil recovery costs. The downhole equipment, the pumping units, the steam generator, and the equipment to remove the gas and water from the oil after it is produced are used directly in the project and are essential to the completeness of the project. Therefore, this equipment is an integral part of the project and the costs of the equipment are qualified enhanced oil recovery costs. Although the building that X constructs as an office and the cars and trucks X purchases to provide transportation for monitoring the wellsites are used directly in the project, they are not essential to the completeness of the project. Therefore, the building and the cars and trucks are not an integral part of the project and their costs are not qualified enhanced oil recovery costs. The cost of the water X purchases from Y is a tertiary injectant expense that is a qualified enhanced oil recovery cost. The storage tanks X acquires to store the water are required to provide a proximate source of water for the production of steam. Therefore, the water storage tank are an integral part of the project and the costs of the water storage tanks are qualified enhanced oil recovery costs.

Example 2. Diluent storage tanks. In 1992, A, the owner of an operating mineral interest, undertakes a qualified enhanced oil recovery project with respect to the property. A acquires diluent to be used in connection with the project. A stores the diluent in a storage tank that A acquires for that purpose. The storage tank provides a proximate source of diluent to be used in the tertiary recovery method. Therefore, the storage tank is used directly in the project and is essential to the completeness of the project. Accordingly, the storage tanks is an integral part of the project and the cost of the storage tank is a qualified enhanced oil recovery cost.

Example 3. Oil storage tanks. In 1992, Z, a corporation and the owner of an operating mineral interest in a property, undertakes a qualified enhanced oil recovery project with respect to the property. Z acquires storage tanks that Z will use solely to store the crude oil that is produced from the enhanced oil recovery project. The storage tanks are not used directly in the project and are not essential to the completeness of the project. Therefore, the storage tanks are not an integral part of the enhanced oil recovery project and the costs of the storage tanks are not qualified enhanced oil recovery costs.

Example 4. Oil refinery. B, the owner of an operating mineral interest in a property, undertakes a qualified enhanced oil recovery project with respect to the property. Located on B's property is an oil refinery where B will refine the crude oil produced from the project. The refinery is not used directly in the project and is not essential to the completeness of the project. Therefore, the refinery is not an integral part of the enhanced oil recovery project.

Example 5. Gas processing plant. C, the owner of an operating mineral interest in a property, undertakes a qualified enhanced oil recovery project with respect to the property. A gas processing plant where C will process gas produced in the project is located on C's property. The gas processing plant is not used directly in the project and is not essential to the completeness of the project. Therefore, the gas processing plant is not an integral part of the enhanced oil recovery project.

Example 6. Gas processing equipment. The facts are the same as in *Example 5* except that C uses a portion of the gas processing plant to separate and recycle the tertiary injectant. The gas processing equipment used to separate and recycle the tertiary injectant is used directly in the project and is essential to the completeness of the project. Therefore, the gas processing equipment used to separate and recycle the tertiary injectant is an integral part of the enhanced oil recovery project and the costs of this equipment are qualified enhanced oil recovery costs.

Example 7. Steam generator costs allocated. In 1988, D, the owner of an operating mineral interest in a property, undertook a steam drive project with respect to the property. In 1992, D decides to undertake a steam drive project with respect to reservoir volume that was substantially unaffected by the 1988 project. The 1992 project is a significant expansion that is a qualified enhanced oil recovery project. D purchases a new steam generator with sufficient capacity to provide steam for both the 1988 project and the 1992 project. The steam generator is used directly in the 1992 project and is essential to the completeness of the 1992 project. Accordingly, the steam generator is an integral part of the 1992 project. Because the steam generator is also used to provide steam for the 1988 project, D must allocate the cost of the steam generator to the 1988 project and the 1992 project. Only the portion of the cost of the steam generator that is allocable to the 1992 project is a qualified enhanced oil recovery cost.

Example 8. Carbon dioxide pipeline. In 1992, E, the owner of an operating mineral interest in a property, undertakes an immiscible carbon dioxide displacement project with respect to the property. E constructs a pipeline to convey carbon dioxide to the project site. E contracts with F, a producer of carbon dioxide, to purchase carbon dioxide to be injected into injection wells in E's enhanced oil recovery project. The cost of the carbon dioxide is a tertiary injectant expense that is a qualified enhanced oil recovery cost. The pipeline is used by E to transport the tertiary injectant, that is, the carbon dioxide to the project site. Therefore, the pipeline is an integral part of the project. Accordingly, the cost of the pipeline is a qualified enhanced oil recovery cost.

Example 9. Water source wells. In 1992, G the owner of an operating mineral interest in a property, undertakes a polymer augmented waterflood project with respect to the property. G drills water wells to provide water for injection in connection with the project. The costs of drilling the water wells are intangible drilling and development costs that are paid or incurred in connection with the project. Therefore, the costs of drilling the water wells are qualified enhanced oil recovery costs.

Example 10. Leased equipment. In 1992, H, the owner of an operating mineral interest in a property undertakes a steam drive project with respect to the property. H contracts with I, a driller, to drill injection wells in connection with the project. H also leases a steam generator to provide steam for injection in connection with the project. The drilling costs are intangible drilling and development costs that are paid in connection with the project and are qualified enhanced oil recovery costs. The steam generator is used to produce the tertiary injectant. The steam generator is used directly in the project and is essential to the completeness of the project; therefore, it is an integral part of the project. The costs of leasing the steam generator are tangible property costs that are qualified enhanced oil recovery costs.

(c) *Primary purpose* -- (1) *In general.* For purposes of this section, a cost is a qualified enhanced oil recovery cost only if the cost is paid or incurred with respect to an asset which is used for the primary purpose of implementing one or more enhanced oil recovery projects, at least one of which is a qualified enhanced oil recovery project. All the facts and circumstances determine whether an asset is used for the primary purpose of implementing an enhanced oil recovery project. For purposes of this paragraph (c), an enhanced oil recovery project is a project that satisfies the requirements of paragraphs (a) (1) and (2) of section 1.43-2.

(2) *Tertiary injectant costs.* Tertiary injectant costs generally satisfy the primary purpose test of this paragraph (c).

(3) *Intangible drilling and development costs.* Intangible drilling and development costs paid or incurred with respect to a well that is used in connection with the recovery of oil by primary or secondary methods are not qualified enhanced oil recovery costs. Except as provided in this paragraph (c)(3), a well used for primary or secondary recovery is not used for the primary purpose of implementing an enhanced oil recovery project. A well drilled for the primary purpose of implementing an enhanced oil recovery project is not considered to be used for primary or secondary recovery, notwithstanding that some primary or secondary production may result when the well is drilled, provided that such primary or secondary production is consistent with the unit plan of development or other similar plan. All the facts and circumstances determine whether primary or secondary recovery is consistent with the unit plan of development or other similar plan.

(4) *Tangible property costs.* Tangible property costs must be paid or incurred with respect to property which is used for the primary purpose of im ple ment ing an enhanced oil recovery project.

If tangible property is used partly in a qualified enhanced oil recovery project and partly in another activity, the property must be primarily used to implement the qualified enhanced oil recovery project.

(5) *Offshore drilling platforms.* Amounts paid or incurred in connection with the acquisition, construction, transportation, erection, or installation of an offshore drilling platform (regardless of whether the amounts are intangible drilling and development costs) that is used in connection with the recovery of oil by primary or secondary methods are not qualified enhanced oil recovery costs. An offshore drilling platform used for primary or secondary recovery is not used for the primary purpose of implementing an enhanced oil recovery project.

(6) *Examples.* The following examples illustrate the principles of this paragraph (c).

Example 1. Intangible drilling and development costs. In 1992, J incurs intangible drilling and development costs in drilling a well. J intends to use the well as an injection well in connection with an enhanced oil recovery project in 1994, but in the meantime will use the well in connection with a secondary recovery project. J may not take the intangible drilling and development costs into account in determining the credit because the primary purpose of a well used for secondary recovery is not to implement a qualified enhanced oil recovery project.

Example 2. Offshore drilling platform. K, the owner of an operating mineral interest in an offshore oil field located within the United States, constructs an offshore drilling platform that is designed to accommodate the primary, secondary, and tertiary development of the field. Subsequent to primary and secondary development of the field, K commences an enhanced oil recovery project that involves the application of a qualified tertiary recovery method. As part of the enhanced oil recovery project, K drills injection wells from the offshore drilling platform K used in the primary and secondary development of the field and installs an additional separator on the platform.

Because the offshore drilling platform was used in the primary and secondary development of the field and was not used for the primary purpose of implementing tertiary development of the field, costs incurred by K in connection with the acquisition, construction, transportation, erection, or installation of the offshore drilling platform are not qualified enhanced oil recovery costs. However, the costs K incurs for the additional separator are qualified enhanced oil recovery costs because the separator is used for the primary purpose of implementing tertiary development of the field. In addition, the intangible drilling and development costs K incurs in connection with drilling the injection wells are qualified enhanced oil recovery costs with respect to which K may claim the enhanced oil recovery credit.

(d) *Costs paid or incurred prior to first injection* -- (1) *In general.* Qualified enhanced oil recovery costs may be paid or incurred prior to the date of the first injection of liquids, gases, or other matter (within the meaning of § 1.43-2(c)). If the first injection of liquids, gases, or other matter occurs on or before the date the taxpayer files the taxpayer's federal income tax return for the taxable year with respect to which the costs are allowable, the costs may be taken into account on that return. If the first injection of liquids, gases, or other matter is expected to occur after the date the taxpayer files that return, costs may be taken into account on that return if the Internal Revenue Service issues a private letter ruling to the taxpayer that so permits.

(2) *First injection after filing of return for taxable year costs are allowable.* Except as provided in paragraph (d)(3) of this section, if the first injection of liquids, gases, or other matter occurs or is expected to occur after the date the taxpayer files the taxpayer's federal income tax return for the taxable year with respect to which the costs are allowable, the costs may be taken into account on an amended return (or in the case of a Coordinated Examination Program taxpayer, on a written statement treated as a qualified return) after the earlier of --

(i) The date the first injection of liquids, gases, or other matter occurs; or

(ii) The date the Internal Revenue Service issues a private letter ruling that provides that the taxpayer may take costs into account prior to the first injection of liquids, gases, or other matter.

(3) *First injection more than 36 months after close of taxable year costs are paid or incurred.* If the first injection of liquids, gases, or other matter occurs more than 36 months after the close of the taxable year in which costs are paid or incurred, the taxpayer may take the costs into account in determining the credit only if the Internal Revenue Service issues a private letter ruling to the taxpayer that so provides.

(4) *Injections in volumes less than the volumes specified in the project plan.* For purposes of this paragraph (d), injections in volumes significantly less than the volumes specified in the project plan, the unit plan of development, or another similar plan do not constitute the first injection of liquids, gases, or other matter.

(5) *Examples.* The following examples illustrate the provisions of paragraph (d) of this section.

Example 1. First injection before return filed. In 1992, L, a calendar year taxpayer, undertakes a qualified enhanced oil recovery project on a property in which L owns an operating mineral interest. L incurs $1,000 of intangible drilling and development costs, which L may elect to deduct under section 263(c) for 1992. The first injection of liquids, gases, or other matter (within the meaning of § 1.43-2(c)) occurs in March 1993. L files a 1992 federal income tax return in April 1993. Because the first injection occurs before the filing of L's 1992 federal income tax return, L may take the $1,000 of intangible drilling and development costs into account in determining the credit for 1992 on that return.

Example 2. First injection after return filed. In 1993, M, a calendar year taxpayer, undertakes a qualified enhanced oil recovery project on a property in which M owns an operating mineral interest. M incurs $2,000 of intangible drilling and development costs, which M elects to deduct under section 263(c) for 1993. The first injection of liquids, gases, or other matter is expected to occur in 1995. M files a 1993 federal income tax return in April 1994. Because the first injection of liquids, gases, or other matter occurs after the date on which M's 1993 federal income tax return is filed in April 1994, M may take the $2,000 of intangible drilling and development costs into account on an amended return for 1993 after the earlier of the date the first injection of liquids, gases, or other matter occurs, or the date the Internal Revenue Service issues a private letter ruling that provides that M may take the $2,000 into account prior to first injection.

Example 3. First injection more than 36 months after taxable year. N, a calendar year taxpayer, owns an operating mineral interest in a property on which N undertakes an immiscible carbon dioxide displacement project. In 1994, N incurs $5,000 in connection with the construction of a pipeline to transport carbon dioxide to the project site. The first injection of liquids, gases, or other matter is expected to occur after the pipeline is completed in 1998. Because the first injection of liquids, gases, or other matter occurs more than 36 months after the close of the taxable year in which the $5,000 is incurred, N may take the $5,000 into account in determining the credit only if N receives a private letter ruling from the Internal Revenue Service that provides that N may take the $5,000 into account prior to first injection.

(e) *Other rules* -- (1) *Anti-abuse rule.* Costs paid or incurred with respect to an asset that is acquired, used, or transferred in a manner designed to duplicate or otherwise unreasonably increase the amount of the credit are not qualified enhanced oil recovery costs, regardless of whether the costs would otherwise be creditable for a single taxpayer or more than one taxpayer.

(2) *Costs paid or incurred to acquire a project.* A purchaser of an existing qualified enhanced oil recovery project may claim the credit for any section 43 costs in excess of the acquisition cost. However, costs paid or incurred to acquire an existing qualified enhanced oil recovery project (or an interest in an existing qualified enhanced oil recovery project) are not eligible for the credit.

(3) *Examples.* The following examples illustrate the principles of paragraph (e) of this section.

Example 1. Duplicating or unreasonably increasing the credit. O owns an operating mineral interest in a property with respect to which a qualified enhanced oil recovery project is implemented. O acquires pumping units, rods, casing, and separators for use in connection with the project from an unrelated equipment dealer in an arm's length transaction. The equipment is used for the primary purpose of implementing the project. Some of the equipment acquired by O is used equipment. The costs paid by O for the used equipment are qualified enhanced oil recovery costs. O does not need to determine whether the equipment has been previously used in an enhanced oil recovery project.

Example 2. Duplicating or unreasonably increasing the credit. P and Q are co-owners of an oil property with respect to which a qualified enhanced oil recovery project is implemented. In 1992, P and Q jointly purchases a nitrogen plant to supply the tertiary injectant used in the project. P and Q claim the credit for their respective costs for the plant. In 1994, X, a corporation unrelated to P or Q, purchases the nitrogen plant and enters into an agreement to sell nitrogen to P and Q. Because this transaction duplicates or otherwise unreasonably increases the credit, the credit is not allowable for the amounts incurred by P and Q for the nitrogen purchased from X.

Example 3. Duplicating or unreasonably increasing the credit. The facts are the same as in *Example 2.* In addition, in 1995, P and Q reacquire the nitrogen plant from X. This constitutes the acquisition of property in a manner designed to duplicate or otherwise unreasonably increase the amount of the credit. Therefore, the credit is not allowable for amounts incurred by P and Q for the nitrogen plant purchased from X.

Example 4. Duplicating or unreasonably increasing the credit. R owns an operating mineral interest in a property with respect to which a qualified enhanced oil recovery project is implemented. R acquires a pump that is installed at the site of the project. After the pump has been placed in service for 6 months, R transfers the pump to a secondary recovery project and acquires a replacement pump for the tertiary project. The original pump is suited to the needs of the secondary recovery project and could have been installed there initially. The pumps have been acquired in a manner designed to duplicate or otherwise unreasonably increase the amount of the credit. Depending on the facts, the cost of one pump or the other may be a qualified enhanced oil recovery cost; however, R may not claim the credit with respect to the cost of both pumps.

Example 5. Acquiring a project. In 1993, S purchases all of T's interest in a qualified enhanced oil recovery project, including all of T's interest in tangible property that is an integral part of the project and all of T's operating mineral interest. In 1994, S incurs costs for additional tangible property that is an integral part of the project and which is used for the primary purpose of implementing the project. S also incurs costs for tertiary injectants that are injected in connection with the project. In determining the credit for 1994, S may take into account costs S incurred for tangible property and tertiary injectants. However, S may not take into account any amount that S paid for T's interest in the project in determining S's credit for any taxable year.

§ 1.43-5 At-risk limitation. [Reserved]

§ 1.43-6 Election out of section 43.

(a) *Election to have the credit not apply* -- (1) *In general.* A taxpayer may elect to have section 43 not apply for any taxable year. The taxpayer may revoke an election to have section 43 not apply for any taxable year. An election to have section 43 not apply (or a revocation of an election to have section 43 not apply) for any taxable year is effective only for the taxable year to which the election relates.

(2) *Time for making the election.* A taxpayer may make an election under paragraph (a) of this section to have section 43 not apply (or revoke an election to have section 43 not apply) for any taxable year at any time before the expiration of the 3-year period beginning on the last date prescribed by law (determined without regard to extensions) for filing the return for the taxable year. The time for making the election (or revoking the election) is prescribed by section 43(e)(2) and may not be extended under § 1.9100-1.

(3) *Manner of making the election.* An election (or revocation) under paragraph (a)(1) of this section is made by attaching a statement to the taxpayer's federal income tax return or an amended return (or, in the case of a Coordinated Examination Program taxpayer, on a written statement treated as a qualified amended return) for the taxable year for which the election (or revocation) applies. The taxpayer must indicate whether the taxpayer is electing to not have section 43 apply or is revoking such an election and designate the project or projects to which the election (or revocation) applies. For any taxable year, the last election (or revocation) made by a taxpayer within the period prescribed in paragraph (a)(2) of this section determines whether section 43 applies for that taxable year.

(b) *Election by partnerships and S corporations.* For partnerships and S corporations, an election to have section 43 not apply (or a revocation of an election to have section 43 not apply) for any taxable year is made, in accordance with the requirements of paragraph (a) of this section, by the partnership or S corporation with respect to the qualified enhanced oil recovery costs paid or incurred by the partnership or S corporation for the taxable year to which the election relates.

§ 1.43-7 Effective date of regulations.

The provisions of §§ 1.43-1, 1.43-2 and 1.43-4 through 1.43-7 are effective with respect to costs paid or incurred after December 31, 1991, in connection with a qualified enhanced oil recovery project. The provisions of § 1.43-3 are effective for taxable years beginning after December 31, 1990. For costs paid or incurred after December 31, 1990, and before January 1, 1992, in connection with a qualified enhanced oil recovery project, taxpayers must take reasonable return positions taking into consideration the statute and its legislative history.

Par. 5. The authority citation for part 602 continues to read as follows:

Authority: *26 U.S.C. 7805.*

Par. 6. Section 602.101(c) is amended by removing the entries in the table for §§ 1.43-2, 1.43-3T(a)(3) and 1.43-3T(b)(3) and adding the following entries in the table to read as follows:

§ 602.101 OMB control numbers.

* * * * *

(c) * * *

CFR part or section where identified and described	Current OMB control No.
* * * * *	
1.32-2	1545-0074
* * * * *	
1.43-3(a)(3)	1545-1292
1.43-3(b)(3)	1545-1292
* * * * *	

Shirley D. Peterson,

Commissioner of Internal Revenue.

Approved: October 21, 1992.

Fred T. Goldberg,

Assistant Secretary of the Treasury.

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