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. 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 × 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 × 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 × 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 × 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 × 50%)).

[T.D. 8448, 57 FR 54923, Nov. 23, 1992; 58 FR 7987, Feb. 11, 1993]

§ 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*—(i) *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.

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