Report of the Committee on Tax Developments

I. INTRODUCTION

The most significant tax issue before the Federal Energy Regulatory Commission (FERC or Commission) in 1987 was the reduction of maximum corporate income tax rates from 46% to 34%, effective July 1, 1987, pursuant to the Tax Reform Act of 1986.[1] The focus of the FERC was to ensure the prompt flow through of this reduction to ratepayers. Thus, the FERC promulgated regulations providing for an abbreviated rate reduction procedure for electric utilities, required the inclusion of tax trackers in negotiated rate settlements of natural gas pipelines, and conditioned the acceptance of tariff sheets on subsequent rate filings to reflect the new income tax rate effective July 1. In Congress, legislative activity in 1987, with respect to tax provisions affecting energy, focused on stimulating domestic oil production. As a result, bills still currently pending in Congress propose to repeal the windfall profits tax on domestic oil production, eliminate the fifty percent net income limitation on percentage depletion, and allow percentage depletion for transferred property.

II. REGULATIONS

A. *Investment Tax Credits*

Treasury Decision (T.D.) 8147[2] adopted final regulations pertaining to the business energy investment credit. Internal Revenue Code (I.R.C.) section 48(l)[3] and Treasury Regulations (Regs.) § 1.48-9[4] define energy property as solar, wind, or geothermal property. Previously, Regs. § 1.48-9 required that, in order to qualify for the tax credit, equipment must use only qualified (i.e., wind, solar, or geothermal) energy. If energy property used both qualified and non-qualified energy sources ("dual use property"), it was not considered to qualify for the tax credit.

T.D. 8147 amended Regs. § 1.48-9 to allow dual use property to qualify, as long as the use of non-qualified energy does not exceed twenty-five percent of the total energy input in the annual measuring period.[5] However, such dual use property qualifies only to the extent of basis or cost allocable to the use of qualified energy. This allocation may be made by comparing the use of qualified and non-qualified energy on a Btu-basis. Nonetheless, the Internal Revenue Service (IRS) may accept any other method of allocation.[6]

The IRS explicitly rejected a safe-harbor test for dual use property based on FERC certification of a qualifying small power production facility under

1. Tax Reform Act of 1986, Pub. L. No. 99-514, 100 Stat. 2085 (1986) (to be codified in various sections of 26 U.S.C.).
2. T.D. 8147, 1987-37 I.R.B. 11.
3. I.R.C. § 48(l) (West Supp. 1987).
4. Treas. Reg. § 1.48-9 (1987).
5. T.D. 8147, 1987-37 I.R.B. 11, 12.
6. *Id.*

18 C.F.R. Part 292.[7] An allocation method based on such FERC certification *may* be accepted by the IRS under appropriate circumstances, but does not amount to a safe-harbor test.[8]

B. Foreign Oil And Gas Extraction Income Limitation

In T.D. 8160,[9] the IRS adopted final regulations pertaining to the limitation on foreign tax credits for taxes paid on foreign oil related income (FORI). In order to prevent the offsetting of excess foreign tax credits generated by extraction income against other non-oil related foreign source income, I.R.C. § 907[10] limits foreign tax credits to a percentage of foreign oil and gas extraction income (FOGEI).[11] The regulations provide that FORI and FOGEI include interest on reasonable amounts of working capital and other amounts related to extraction, processing and other activities under I.R.C. § 907(c)(1), (2).[12] Moreover, FOGEI includes all income from extraction services as long as it is based on output.[13] Finally, the regulations amend Regs. § 1.901-1(d) to provide that a taxpayer may elect the foreign tax credit at any time during the ten year period of limitations under I.R.C. § 6511(d)(3)(A).[14]

C. Reduced Corporate Income Tax Rates

The FERC issued final regulations to account for the reduction of the maximum corporate income tax rate from 46% to 34%, as provided for by the Tax Reform Act of 1986.[15] The regulations provide a voluntary, abbreviated rate filing procedure that will allow electric utilities to file for rate decreases under section 205 of the Federal Power Act,[16] to reflect the decrease in the federal income tax rate.[17] Since the abbreviated filing procedure is voluntary, the FERC tried to encourage utilities to file rate reductions under this rule by not requiring interest on resultant refunds.[18]

The FERC noted that the reduction in the federal corporate income tax rate will also impact on natural gas and oil pipelines. However, the new abbreviated rate filing procedure applies only to electric utilities, because the

7. *Id.* One of the criteria for FERC certification is that 75% or more of the total energy input must be from biomass, waste, renewable resources or geothermal resources and that the aggregate use of oil, coal, and natural gas not exceed 25% of the total energy input during any calendar year period. 18 C.F.R. § 292.204(b) (1987).

8. T.D. 8147, 1987-37 I.R.B. 11, 12.

9. T.D. 8160, 1987-45 I.R.B. 10.

10. I.R.C. § 907 (West Supp. 1987).

11. "FOGEI is foreign source taxable income derived from the extraction of minerals from oil or gas wells or from the sale or exchange of assets used in the extraction activity." T.D. 8160, 1987-45 I.R.B. 10, 11.

12. T.D. 8160, at 11.

13. *Id.*

14. *Id.* at 12.

15. Order No. 475, *Elective Utilities; Rate Changes Relating to Federal Corporate Income Tax Rates for Public Utilities*, III F.E.R.C. Stats. & Regs. ¶ 30,752, 52 Fed. Reg. 24,987 (1987), *reh'g denied*, Order 475-A, 41 F.E.R.C. ¶ 61,029 (1987).

16. 16 U.S.C. § 824d (1982).

17. Order No. 475, III F.E.R.C. Stats. & Regs. ¶ 30,752, at 30,371 (1987).

18. *Id.* at 30,732.

rates of natural gas companies will be automatically adjusted due to the inclusion of tax trackers in the majority of natural gas pipeline rate settlements. Changes in oil pipeline rates will be made on a case-by-case basis.[19]

III. COURT AND COMMISSION DECISIONS

A. *Reduced Corporate Income Tax Rates*

The FERC has routinely conditioned the acceptance of rate filings on the inclusion of clauses reflecting the reduction of maximum corporate income tax rates from 46% to 34% effective July 1, 1987.[20] Although the new corporate income tax rate of 34% did not take effect until July 1, 1987, the FERC did not allow rate filings based on a "blended" tax rate for the entire calendar year.[21] Similarly, the FERC has required the inclusion of "tax tracker" clauses in negotiated rate settlements to reflect income tax rates in effect at the time the rate schedules become effective.[22]

In *Ocean State Power*,[23] the FERC determined that the rates filed by Ocean State were not just and reasonable, inter alia, because the tax component of the rate did not reflect the reduction of corporate tax rates under the Tax Reform Act of 1986.[24] The Commission directed Ocean State to revise the tax component of its rate accordingly to reflect the reduced corporate tax rates.[25] Moreover, the Commission determined that Ocean State will be treated as a corporation for ratemaking purposes, even though it is a partnership which passes through tax liabilities to the individual partners. As a result, Ocean State must include tax effects of transactions in its filings under the Uniform System of Accounts as if it were a corporation.[26]

In *Pacific Gas & Electric Co.*,[27] the administrative law judge (ALJ) referred to the Commission the following policy issues relating to tax treatment under the Tax Reform Act of 1986: (1) whether there is a Commission policy favoring the use of a single item tax tracker which adjusts rates at least annually in order to reflect savings attributable to changes in federal tax law; (2) whether such a policy overrides the policy favoring negotiated rate settle-

19. *Id.* at 30,739.

20. *See, e.g.*, Ozark Gas Transmission Sys., 41 F.E.R.C. ¶ 61,207 (1987); ANR Pipeline Co., 41 F.E.R.C. ¶ 63,017 (1987); Williams Natural Gas Co., 41 F.E.R.C. ¶ 61,074 (1987); South Ga. Natural Gas Co., 40 F.E.R.C. ¶ 61,224 (1987); Transcontinental Gas Pipeline Corp., 40 F.E.R.C. ¶ 61,192 (1987).

21. West Tex. Utils. Co., 38 F.E.R.C. ¶ 61,138 at 61,369 n.5 (1987); *see* Williams Natural Gas Co., 41 F.E.R.C. ¶ 61,141 (1987); MIGC, Inc., 41 F.E.R.C. ¶ 61,020 (1987).

22. Natural Gas Pipeline Co., 38 F.E.R.C. ¶ 61,248 at 61,838 (1987) (tax tracker approved). *See* Northwest Cent. Pipeline Corp., 38 F.E.R.C. ¶ 61,170 at 61,550 (1987) (limits broad tax tracker language to changes in income tax rates only); Texas E. Transmission Corp., 37 F.E.R.C. ¶ 61,260 at 61,683 (1986) (limits tax tracker language). The FERC policy to require the inclusion of tax trackers in negotiated rate settlements was expressed in Tennessee Gas Pipeline Co., 32 F.E.R.C. ¶ 61,311, at 61,730, *reh'g denied*, 33 F.E.R.C. ¶ 61,199 (1985). *See* High Island Offshore Sys., 32 F.E.R.C. ¶ 61,164, at 61,400 (1985). *But see infra* note 29 and accompanying text.

23. Ocean State Power, 38 F.E.R.C. ¶ 61,140 (1987).

24. 38 F.E.R.C. at 61,379.

25. *Id.*

26. *Id.*

27. Pacific Gas & Elec. Co., 38 F.E.R.C. ¶ 63,036 (1987).

ments; and (3) whether such a tax tracker can be required without the consent of the settling parties.[28]

The Commission decided to let the negotiated rate settlement stand in spite of its reference to the superseded forty-six percent corporate income tax rate.[29] Thus, the FERC allowed Pacific Gas & Electric Co. (PG&E) to make overcollections until the next rate filing in 1991, because of the policy favoring negotiated rate settlements and because PG&E had agreed to refund these overcollections with interest.[30] However, the FERC explicitly stated that it does not generally endorse the deferral of passing through benefits to ratepayers, and that its decision was limited to the particular case.[31]

In *Southern Pacific Pipe Lines, Inc.*,[32] the ALJ determined that Southern Pacific's oil pipeline rates are not just and reasonable and that, therefore, the rate increases should be refunded.[33] Southern Pacific had, inter alia, included accumulated deferred income taxes (ADIT) and the allowance for funds used during construction (AFUDC) in its starting rate base, and took a depreciation allowance on the AFUDC added to the rate base.[34] The ALJ held that AFUDC is properly included in the starting rate base, but that oil pipelines cannot depreciate the AFUDC component.[35] Moreover, it was held that ADIT cannot be included in the starting rate base by oil pipelines pursuant to the holding in *Williams Pipe Line Co.*[36]

B. Issues in Determining Taxable Income

In *Pritchett v. Commissioner*,[37] the Ninth Circuit had to determine whether limited partners in an oil and gas drilling venture were "at risk" with respect to certain recourse notes and, thus, entitled to deduct distributive shares of noncash partnership losses.[38] In a split decision (9-7), the tax court had affirmed the position of the IRS, that each taxpayer was at risk only to the extent of his actual cash contribution, and had, therefore, denied the deductibility of partnership losses on that basis.[39]

In reviewing the facts of the case, the Ninth Circuit found that five partnerships had entered into agreements with Fairfield Drilling Corp., which agreed to drill and develop productive wells in exchange for cash and recourse

28. *Id.* at 65,225.

29. Pacific Gas & Elec. Co., 40 F.E.R.C. ¶ 61,068 (1987). PG&E's rate settlement did not include a tax tracker to reflect changes in corporate income tax rates in spite of the FERC policy requiring such a clause. *See supra* note 22 and accompanying text.

30. *Id.* at 61,207.

31. *Id.*

32. Southern Pac. Pipe Lines, Inc., 39 F.E.R.C. ¶ 63,018 (1987).

33. *Id.*

34. *Id.* at 65,088.

35. *Id.* The ALJ stated that the FERC's regulations provide for AFUDC amortization for natural gas pipelines, but not for oil pipelines, because gas pipelines have inflation built into equity rates of return while oil pipelines do not.

36. *Id.* at 65,088-89; Williams Pipe Line Co., 33 F.E.R.C. ¶ 61,327 at 61,639 (1985).

37. Pritchett v. Commissioner, 827 F.2d 644 (9th Cir. 1987).

38. *Id.* at 645.

39. Pritchett v. Commissioner, 85 T.C. 580 (1985).

notes. The recourse notes in question were secured by each partnership's assets, were noninterest-bearing, and matured in fifteen years. The principal of the notes was to be paid from the net income distributed to each partnership if drilling were successful. Only the general partners in each partnership were personally liable for the notes. However, the partnership agreement provided that if the notes were not paid off at maturity, the limited partners were personally obligated to make additional capital contributions to cover the deficiency.[40]

The Ninth Circuit held "that the liability of the limited partners was unavoidable and hence not contingent."[41] The "cash call" provision contradicts the conclusion of the tax court and the IRS that the taxpayers were not at risk on the recourse debt.[42] However, the court remanded the case to the tax court for its consideration of other issues.[43]

In *Indianapolis Power & Light Co.*,[44] the tax court held that deposits required by an electric utility from uncreditworthy customers were not income within the meaning of I.R.C. § 61. The security deposits had generally been credited against the customer account and the remainder had been returned by check. The tax court held that the security deposits were, in fact, deposits and not advance payments because the deposits were not required from most customers and were treated as the customer's funds, as indicated by customer control over ultimate disposition, and by payment of interest on the deposits.[45]

In *Iowa Southern Utilities Co. v. United States*,[46] the United States Claims Court held that a customer surcharge[47] covering plant construction financing costs of an electric utility is taxable income in the years it is collected. In 1976, Iowa Southern had begun construction of a $350 million coal-fired powerplant. The Iowa State Commerce Commission approved the repayable surcharge to be imposed during the period of construction from 1978 until 1981. Iowa Southern collected $12.3 million in surcharges but did not include surcharge receipts as income in its consolidated federal tax returns, which resulted in an IRS deficiency assessment for those years.[48] Upon review, the court concluded that the IRS had properly assessed these surcharges as income because tariff sheets referred to the surcharge as a rate increase, the utility's bills included this surcharge as a cost of electricity, and Iowa Southern had unrestricted use of the revenues. As a result, the surcharges are income and not loans from customers; refunding the surcharge

40. *Pritchett*, 827 F.2d at 645.

41. *Id.* at 647.

42. *Id.*

43. *Id.* at 648.

44. Indianapolis Power & Light Co. v. Commissioner, 88 T.C. 964 (1987).

45. *Id.* at 976-78. The tax court followed the precedent set in City Gas Co. v. Commissioner, 74 T.C. 386 (1980).

46. Iowa S. Util. Co. v. United States, 11 Cl. Ct. 868, *appeal docketed*, No. 87-1339 (Fed. Cir. May 7, 1987).

47. The surcharge for construction cost imposed during the years of construction (1978-1981) was refundable to ratepayers over the thirty-year life of the asset (without interest) as a negative surcharge.

48. *Iowa S. Util.*, 11 Cl. Ct. at 871.

will merely reduce taxable income in future years.[49]

In *Electric Energy, Inc. v. United States*,[50] the United States Claims Court considered settlement payments made by the Department of Energy (DOE) to a venture formed by four utilities to supply a DOE uranium enrichment facility with power. The DOE had reduced its take under the contract with the venture, and had made payments under a settlement of the claim for damages resulting from DOE's reduced take. The court held that the DOE payments were not income to Electric Energy because the venture only acted as a conduit for the sponsoring companies (the utilities) owning the venture and credited the distributive share of the DOE surcharges to the utilities.[51]

In *Mulga Coal Co. v. United States*, the Eleventh Circuit held that the excise tax under I.R.C. § 4121 was not payable for coal used as fuel to dry coal produced for sale.[52] Mulga had excluded the weight of coal used as fuel for dryers in the processing of its coal production from the total amount of coal it mined and sold for excise tax purposes. The IRS contended that the coal used as fuel in the coal dryers must be included in the total taxable tonnage of coal. The district court disagreed with the IRS and held that the excise tax does not apply to the coal used as fuel in Mulga's dryers.[53]

The Eleventh Circuit affirmed, reasoning that the coal used as fuel is not treated as "sold" for percentage depletion purposes and, therefore, cannot be treated as "sold" for excise tax purposes.[54] Regs. § 48.4121-1 provides that a mining process is determined the same way for excise tax purposes as it is for percentage depletion purposes. Thus, the coal used by Mulga in its dryers cannot be included in gross income for percentage depletion purposes and, therefore, is not subject to the excise tax under I.R.C. § 4121.[55]

The Second Circuit held in *Howe v. Commissioner*,[56] that an advanced minimum royalty payment under a coal mining lease is not deductible under I.R.C. § 612 and Regs. § 1.612-3(b)(3), because payments were neither uniform nor periodic. The taxpayer had purchased an investment unit in a coal mining lease resulting in an obligation to pay cash and a nonrecourse note. The tax court denied the deduction of the sum as an advanced minimum royalty payment on the coal lease because the payment does not fall within Regs. § 1.612-3(b)(3), which requires annual uniform payments over the life of the lease.[57]

The Second Circuit affirmed, based on its decision in *Brown v. Commis-*

49. *Id.* at 871-74.

50. Electric Energy, Inc. v. United States, 13 Cl. Ct. 644 (1987).

51. *Id.*

52. Mulga Coal Co. v. United States, 825 F.2d 1547 (11th Cir. 1987).

53. *Id.* at 1548.

54. *Id.* at 1549. In Roundup Coal Mining Co. v. Commissioner, 20 T.C. 388 (1953), the tax court had held that coal used as fuel in mining operations could not be included in gross income for depletion purposes, because the taxpayer had not realized income from that use of coal.

55. *Mulga*, 825 F.2d at 1548. *See* Treas. Reg. § 48.4121-1(d)(3) (1986).

56. Howe v. Commissioner, 814 F.2d 98 (2d Cir. 1987).

57. Regs. § 1.612-3(b)(3) requires payments to be (1) substantially uniform, (2) annual, (3) for the life of the lease, and (4) without regard to actual coal production, for a valid claim to a deduction as an "advanced minimum royalty."

sioner.[58] In *Brown*, the court had held that the test is whether the failure to make a specified annual payment can result in the loss of all lease rights within the one-year period for which payment is due.[59] Under the provisions governing the coal mining sublease, however, the taxpayer's obligations under the nonrecourse promissory note could not be enforced in less than fifteen months after each payment. Thus, the lease permits the taxpayer to withhold his payments without penalty of forfeiture for over a year, and the taxpayer's obligations, therefore, do not meet the *Brown* test.[60]

Moreover, the Second Circuit held that given the sublease's various provisions for set-offs and staggered payment, the payments are neither substantially uniform nor periodic.[61] The court reasoned that absent the requirement of actual payment on an annual basis, the use of nonrecourse notes would enable individuals to realize inflated deductions without having to make the underlying outlays.[62]

Similarly, the tax court considered the issue of advanced minimum royalties in *Charles J. Heitzman.*[63] Here, the taxpayer was a limited partner in Stonehurst Energy Partners, a California limited partnership acquiring, developing and operating oil and gas leases in Oklahoma. The tax court held that taxpayer's 1979 payment for minimum royalties were not deductible, because the royalties *accrued* annually, but were not payable in the absence of production until 1994; production did not commence until 1980. As a result, the royalty payments do not fall within the annual payment and substantial uniformity requirements of a minimum royalty provision under Regs. § 1.612-3(b)(3).[64]

IV. IRS Private Letter Rulings

A. Normalization and Other Tax Accounting Matters

In Private Letter Ruling 87-35-011,[65] a regulated public utility providing gas and electric service sold certain utility property to another unaffiliated public utility engaged in natural gas transportation and distribution; the property sold retained its public utility property status. The IRS ruled that in such a taxable sale of public utility property, the unamortized and unrecaptured accumulated deferred investment tax credits (ADITCs) related to that property do not follow the assets but stay with the seller. Moreover, the IRS held that the purchasing utility would violate the normalization requirements of I.R.C. § 46(f) if the taxpayer's rate base or cost of service is reduced for amortization of these ADITCs.[66]

58. Brown v. Commissioner, 799 F.2d 27 (2d Cir. 1986).
59. *Id.* at 31.
60. *Howe*, 814 F.2d at 101.
61. *Id.*
62. *Id.* at 102.
63. Charles J. Heitzman, 87 T.C.M. (P-H) ¶ 109 (1987).
64. *Id.* at 566.
65. Priv. Ltr. Rul. 87-35-011 (May 26, 1987).
66. *Id.*

In Private Letter Ruling 87-45-005,[67] a regulated public utility had similarly sold certain assets with regulatory approval. The regulatory agency had directed that unamortized ADITCs relating to the property transferred be included in the selling utility's share of sales gain; the amount was paid into escrow pending a ruling by the IRS. The IRS ruled that no portion of the unamortized ADITCs remaining could be used to reduce the seller's cost of service without violating the normalization requirements of I.R.C. § 46(f)(2). The IRS reasoned that the utility had sold the asset that generated the investment tax credit and, therefore, the asset, for which the "regulated depreciation expense" was computed under Regs. § 1.46-6(g)(2) for cost of service purposes, is no longer available.[68]

B. *Deductions and Exclusions*

1. Intangible Drilling and Development Costs

In Private Letter Ruling (Technical Advice Memorandum) 87-28-004,[69] the issue was whether the taxpayer could deduct intangible drilling and development costs (IDCs) incurred in drilling injection wells for enhanced hydrocarbon recovery under I.R.C. § 263(c) and under Regs. § 1.612-4. The IRS held that the injection wells are "wells" within the meaning of I.R.C. § 263(c) and that, therefore, the costs for drilling those wells or recompleting formerly producing wells are deductible as IDCs pursuant to Regs. § 1.612-4(a).[70]

2. Depletion Deduction for Intercompany Transaction

In Revenue Ruling (Rev. Rul.) 87-60,[71] the IRS ruled on the depletion deduction in intercompany transactions. A regulated public utility (*X*) selling nuclear generated electricity acquired operating mineral rights from an affiliated corporation (*Y*) owning properties with uranium deposits; in return, *X* paid royalties to *Y* in the year the minerals were produced.[72] *X* used the uranium produced under the royalty agreement to manufacture uranium pellets to be used as the fuel elements in *X*'s nuclear reactors. *X* charged the royalty payments to a capital account as part of the depreciable basis in nuclear fuel elements used for the nuclear generation of electricity.[73]

Y recognizes royalty income when the royalty is received or when the right to payment arises. However, because the transaction that gives rise to

67. Priv. Ltr. Rul. 87-45-005 (Aug. 3, 1987).

68. *Id.*

69. Tech. Adv. Mem. 87-28-004 (Mar. 18, 1987).

70. *Id.* The IRS noted that the issue is governed by the following case law: Page Oil Co. v. Commissioner, 41 B.T.A. 952 (1940), *aff'd on other grounds*, 129 F.2d 768 (2d Cir. 1942) ("water wells" are similar to, and require same tax treatment as, oil wells); Rev. Rul. 69-583, 1969-2 C.B. 41 (IDCs incurred for injection wells can be deducted under I.R.S. § 263(c)); Sun Co. v. Commissioner, 74 T.C. 1481 (1980), *aff'd*, 677 F.2d 294 (3d Cir. 1982).

71. Rev. Rul. 87-60, 1987-28 I.R.B. 9.

72. *X* and *Y* file consolidated income tax returns under the accrual method, but operate as separate entities.

73. Rev. Rul. 87-60, at 10.

the royalty is a deferred intercompany transaction,[74] the income is deferred. The transaction is considered to be a deferred transaction because *X* capitalizes the royalty payments as a depreciable expenditure.[75] The IRS held that *Y* cannot claim depletion deductions until the royalty income is "taken into income."[76] Pursuant to Regs. § 1.1502-13(d)(1), the royalty is taken into income by *Y* when depreciation is taken by *X* on the manufacturered mineral product, i.e., the uranium pellets. As a result, *Y* cannot deduct the depletion allowance at the time *X* pays the royalty, but must wait until *X* takes depreciation on the basis in nuclear fuel elements, which includes the royalty payments.[77]

C. *Mineral Interests and Royalties*

1. Percentage Depletion Under I.R.C. § 613A

In Private Letter Ruling 87-23-073,[78] an independent oil and gas producer had contributed its interest in proven properties to a partnership in exchange for an interest in the partnership. The partnership agreement provided for compensation through a distributive share of income before payout and an increased distributive share of income after payout. The taxpayer inquired whether percentage depletion would be available under I.R.C. § 613A with respect to income received under the partnership agreement. The IRS ruled that the taxpayer is entitled to percentage depletion on the share of income before payout because the taxpayer will not be a "transferee." Moreover, taxpayer is entitled to percentage depletion on the increased share of income after payout because the additional amount is a "reversionary interest" which reverts at the time of payout and is, therefore, not a transfer.[79]

2. Aggregation of Non-Operating Interest

In Private Letter Ruling 87-29-042,[80] a corporation had engaged in a program to acquire nonoperating oil and gas royalty or mineral interests; the program was initiated to reduce the administrative costs of such acquisitions. The IRS ruled that the taxpayer is permitted to aggregate its mineral and royalty interest in adjacent tracts under I.R.C. § 614(e).[81]

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74. Regs. § 1.1502-13(a)(2) provides that the term "deferred intercompany transaction" means (i) the sale or exchange of property, (ii) the performance of services in a case where the amount of the expenditure for such services is capitalized, or (iii) any other expenditure in a case where the amount of the expenditure is capitalized in an intercompany transaction.

75. Rev. Rul. 87-60, at 10.

76. *Id.*

77. *Id.* at 11.

78. Priv. Ltr. Rul. 87-23-073 (Mar. 12, 1987).

79. *Id.*

80. Priv. Ltr. Rul. 87-29-042 (Apr. 21, 1987).

81. *Id.* Regs. § 1.614-5(d) provides that a taxpayer may aggregate such interests in two or more adjacent tracts of land if the taxpayer can establish that the purpose in aggregation is not the avoidance of tax. The IRS stated that the term "two or more adjacent tracts or parcels of land" means tracts or parcels that are in reasonably close proximity to each other depending on the facts and circumstances of each case. Treas. Reg. § 1.614-5(d) (1987).

D. *Nuclear Plant Decommissioning Expenses*

In four letter rulings,[82] the IRS approved proposed Schedules of Ruling Amounts which are required to fund future decommissioning expenses under I.R.C. § 468A.

E. *Tax Exempt Financing: Private Activity Bonds (Nuclear Plants)*

In Rev. Rul. 87-30,[83] the IRS ruled that nuclear generating plants cannot be financed with tax-exempt private activity bonds under I.R.C. §§ 141(d)(1)(A) and 142(a)(8). Private activity bonds issued to provide financing for "facilities for the local furnishing of electric energy or gas" are tax-exempt under certain conditions. I.R.C. § 142(f) defines the local furnishing of electric energy or gas as service to an area consisting of a city and two contiguous counties.[84] The I.R.S. ruled that no portion of a nuclear plant can qualify as such a facility for the local furnishing of electric energy or gas, because the plant is an integrated facility that will furnish electricity to an area larger than two contiguous counties.[85]

F. *Issues in Determining Basis in Property: Capital Advances by DOE (Depreciation)*

In General Counsel Memorandum 39,583,[86] the IRS determined that capital advances received from the Department of Energy (DOE) by a general partnership engaged in synthetic fuel production cannot be used to establish basis in the assets acquired with those funds, or for the purposes of tax credits and depreciation deductions.[87] The DOE had advanced funds to the partnership under the Federal Non-Nuclear Research and Development Act of 1974,[88] for plant construction and equipment acquisition. The repayment of the advances was contingent upon production being economical and upon continued operation of the plant by the partnership. The substantial repayment contingency precludes the partnership from obtaining any basis in the assets purchased with the advances. Pursuant to *Denver & Rio Grande R.R. Co. v. United States*,[89] basis is disallowed because the likelihood that the advances will never have to be repaid in view of the substantial repayment contingency.[90]

V. Legislative Developments

Pursuant to section 3102 of the Omnibus Budget Reconciliation Act of

82. Priv. Ltr. Rul. 87-37-031 (June 15, 1987); Priv. Ltr. Rul. 87-37-032 (June 15, 1987); Priv. Ltr. Rul. 87-42-019 (July 16, 1987); Priv. Ltr. Rul. 87-49-025 (Sept. 3, 1987).
83. Rev. Rul. 87-30, 1987-16 I.R.B. 4.
84. *Id.*
85. *Id.*
86. Gen. Couns. Mem. 39,583 (Nov. 25, 1986).
87. *Id.*
88. 42 U.S.C. § 5907 (1982).
89. Denver & Rio Grande R.R. Co. v. United States, 505 F.2d 1266 (Ct. Cl. 1974).
90. Gen. Couns. Mem. 39,583 (Nov. 25, 1986).

1986,[91] the President's views, on legislative and administrative action necessary to prevent imports of crude oil or petroleum products from exceeding a level that threatens national security, are to be transmitted to Congress based on a Department of Energy study on energy security reported to the President.

The March 1987 Department of Energy report on energy security (DOE report)[92] provides a comprehensive analysis of the energy outlook, and evaluates various tax and other options for addressing energy security concerns.[93] Tax incentives discussed in the DOE report include repeal of the crude oil windfall profit tax; an increase in the percentage depletion rate from 15% to 27.5%, either for independent producers and royalty owners (as under present law), or for all new domestic production; an increase in the net income limitation, from 50% to 100%; repeal of the percentage depletion anti-transfer rules; treatment of geological and geophysical (G&G) costs as expensible intangible drilling and development costs (IDCs); and a five percent income tax credit, either for all drilling and exploration costs or for G&G expenditures only. The report assesses the advantages and disadvantages associated with each of these options and estimates the revenue loss, as well as the increased oil and gas production likely to result from each option; however, it does not specifically recommend any option.[94]

In a message to the Congress on May 6, 1987 (the President's proposal), President Reagan made three recommendations for tax legislation to strengthen the domestic oil industry based on the DOE report.[95] The President's tax proposals were: (1) repealing the crude oil windfall profit tax, effective October 1, 1987 (also included in the President's FY 1988 Budget);[96] (2) increasing the net income limitation on percentage depletion, from 50% to 100% of net income from the property; and (3) allowing transferred property to qualify for percentage depletion. Two separate bills including these tax proposals have been introduced in the Senate: the Energy Security Act of 1987[97] and Income Tax Amendments Related to Domestic Oil and Gas Production.[98]

According to some observers of these tax proposals, the repeal of the Windfall Profits Tax (WPT) is the most likely to be enacted. The full Senate approved S. 255, the WPT repeal bill, with a vote of 58-40, and made it part of the Senate version of the Omnibus Trade and Competitiveness Act of 1987

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91. Omnibus Budget Reconciliation Act of 1986, Pub. L. No. 99-509, § 3102, 100 Stat. 1874, 1888-89.

92. UNITED STATES DEPARTMENT OF ENERGY, ENERGY SECURITY: A REPORT TO THE PRESIDENT OF THE UNITED STATES 74 (1987) [hereinafter DOE REPORT].

93. *Id.*; *see* STAFF OF JOINT COMMITTEE ON TAXATION, 100TH CONG., 1ST SESS., DESCRIPTION OF TAX PROPOSALS RELATING TO DOMESTIC OIL AND GAS PRODUCTION AND ENERGY SECURITY (Comm. Print 1987).

94. DOE REPORT at 76.

95. President's Message to Congress on Energy Security, 23 WEEKLY COMP. PRES. DOC. 490 (May 6, 1987).

96. The Senate Finance Committee also recommended inclusion of this provision in the 1988 Budget.

97. Energy Security Act of 1987, S. 846, 100th Cong., 1st Sess. (1987) (Sen. Nickels, R-Okla.).

98. Income Tax Amendments Related to Domestic Oil and Gas Production, S. 233, 100th Cong., 1st Sess. (1987) (Sen. Boren, D-Okla.).

(the Trade Bill), S. 1420. Moreover, the Chairman of the House Committee on Energy and Commerce[99] recommended adoption of the Senate provisions repealing the WPT by the House conferees considering the Trade Bill. Finally, the Senate Finance Committee also advocated repeal of the WPT as part of the Budget Bill. In view of the earlier inclusion of the WPT repeal provisions in the Trade Bill by the full Senate, this action was widely interpreted as an "insurance policy" to ensure repeal of the WPT even if the House conferees remove the WPT repeal provisions from the Trade Bill, or if the Trade Bill should fail as a whole.

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99. Rep. John Dingell (D-Mich.), an early proponent of the WPT, together with oil-state legislators, sent an open letter to the Chairman of the House Ways and Means Committee urging adoption of the Senate provisions repealing the WPT.