Report of the Committee on Tax Developments

I. Introduction

Under the Omnibus Budget Reconciliation Act of 1990[1] (1990 Act), domestic producers received some of the largest tax breaks in the budget. The tax incentives and relief provided by the 1990 Act include an alternative minimum tax relief, additional percentage depletion relief, enhanced recovery incentives, and an extension of the nonconventional fuel energy credit for gas produced from tight sands formations.

The Internal Revenue Service (IRS or Service) issued several clarifications regarding nonconventional fuel energy credits and percentage depletion allowances. It issued proposed regulations regarding qualifications for nuclear decommissioning funds and modified its positions regarding whether certain transfers of property would be considered contribution in aid of construction (CIAC). Also of note was a court of appeals decision which overturned the Tax Court's holding that deductions for interest and losses could not be made for an energy partnership that had gone into default.

II. Budget

Under the 1990 Act, domestic energy producers were one of the few groups to obtain a significant tax break under the 1991 fiscal year budget. The total package is worth approximately $2.6 billion over five years.[2] The incentives include the following:

A. *Alternative Minimum Tax Relief*

One of the major tax breaks for independent oil and gas producers comes in the form of relief from the alternative minimum tax (AMT) when the price of oil during the previous calendar year is $28 per barrel or less.[3] While all corporate and individual taxpayers must compute AMT, taxpayers other than integrated oil companies as defined in section 613A of the Internal Revenue Code (Code) are allowed to deduct a portion of their intangible drilling cost (IDC) and depletion preference items. Taxpayers may deduct 75% of the IDC preference relating to exploration and 15% of the other IDC. Also, taxpayers may deduct 50% of depletion preference relating to stripper wells so long as the price of oil is $28 or less; if the price of oil rises above $28 per barrel, the deduction is phased out. Further, the 1990 Act expands the definition of stripper wells to include those wells that produce 15 barrels per day or less.[4] The definition under the old windfall profits tax was limited to wells producing 10 barrels per day.[5]

1. Omnibus Budget Reconciliation Act of 1990, Pub. L. No. 101-508, 104 Stat. 1388 (1990).
2. Press release from Sen. David Boren (D-Okla.) (October 27, 1990).
3. § 11531, 104 Stat. 1388, 1388—488-90.
4. § 11523, 104 Stat. 1388, 1388—486-87.
5. Crude Oil Windfall Profits Act of 1980, 26 U.S.C. § 4994 (1982) (incorporating 10 C.F.R. § 212.54(c) (1979)) (repealed 1988).

In addition, the 1990 Act modifies and clarifies the definitions of "qualified exploratory costs" and "exploratory well."[6] In general, qualified exploratory costs are the intangible costs attributable to drilling a domestic oil or gas well that an independent producer may elect to deduct as expenses under section 263(c) of the Code.

An exploratory well is a new well that does not have a completed oil or gas well capable of production in commercial quantities within 1.25 miles at the time of its completion. A new well can also qualify as exploratory if it is at least 800 feet below the depth of any other well within the 1.25 mile radius. Finally, a new well may qualify as exploratory even if it fails the distance and depth tests, so long as it is drilled into a new reservoir of oil or gas.

B. *Percentage Depletion*

The 1990 Act provides relief for small producers by removing current restrictions on percentage depletion deduction.[7] The 1990 Act repeals the 50% net income limitation and allows the percentage depletion to be used to reduce to zero the amount of taxable income attributable to a property. The Act did not repeal the 65% taxable income limit under section 613A(d)(1) of the Code.

In addition, the 1990 Act increases the amount of deduction for marginal properties.[8] However, the class of producers eligible for percentage depletions was not expanded.

C. *Enhanced Recovery Incentives*

The 1990 Act provides $213 million in incentives over five years for enhanced oil recovery.[9] It adds an enhanced oil recovery credit as a component of the general business credit equal to 15% of the qualified costs attributable to qualified enhanced oil recovery projects.[10] This credit covers costs paid or incurred in enhanced oil recovery projects begun or significantly expanded after December 31, 1990.

D. *Nonconventional Fuels*

The 1990 Act extends the nonconventional fuel credits under section 29 of the Code to any gas produced from tight sands formations.[11] It also extends the sunset date of the credit for two years. The credit is available for production from wells drilled before 1993 or produced in a facility placed in service before 1993 and sold before January 1, 2003.

6. § 11531, 104 Stat. 1388, 1388—488-90.

7. § 11522, 104 Stat. 1388, 1388—486.

8. § 11523, 104 Stat. 1388, 1388—486-87.

9. JOINT COMMITTEE ON TAXATION, 101ST CONG. 2D SESS., BUDGET RECONCILIATION (H.R. 5835)-REVENUE PROVISIONS AS REPORTED BY THE CONFEREES (Comm. Print 1990).

10. § 11511, 104 Stat. 1388, 1388—483-85.

11. § 11501, 104 Stat. 1388, 1388—479-80.

III. Developments Affecting the Oil and Gas Industries

A. *Section 613A: Percentage Depletion*

1. IRS Rulings

In Revenue Ruling 90-62,[12] the Service held that for the purposes of Code section 613A, the representative market or field price (RMFP) serves as a cap on the income that the taxpayer may take into account for depletion purposes. In this case, the taxpayer owned an operating interest in a gas-producing reservoir. The taxpayer sold gas on a delivered basis under long-term fixed-price contracts. In calculating his depletion deduction, the taxpayer determined his gross income upon the RMFP rather than on the lower price which the taxpayer received for the gas on a delivered basis. The issue was whether the gross income from the property should be calculated based on the RMFP if the contract price was less. The service held that if the gas was sold after removal from the premises for a price less than the RMFP, then the percentage depletion deduction should be computed without regard to the RMFP. The rationale of the decision was that the RMFP is assumed to be a value of the gas prior to transportation. The RMFP functions as a ceiling on taxpayer income for depletion purposes. Thus, if the contract price is less than the RMFP, the ceiling established by the RMFP is irrelevant.

In Private Letter Ruling 90-14-024,[13] the IRS determined that a merger among three oil and gas entities does not affect the owners' right to use percentage depletion. The case involved two taxpayers each owning a one-half interest in a partnership and two corporations. The partnership owned proven oil and gas properties. The taxpayers applied the percentage depletion allowance to those properties as an offset against income. One of the corporations owned a pipeline and pipeline rights of way for the transportation of oil and gas, while the second corporation transported the gas and received transportation income. To eliminate record keeping difficulties, the taxpayers proposed that the partnership and first corporation merge into the gas transportation corporation. Afterwards, the other two entities would be dissolved. The Service held that if the surviving corporation's election under subchapter S remained valid, then the taxpayers would not be transferees under section 613A(c)(9) and the transfer would not affect the taxpayers' right to use percentage depletion to the extent they were previously entitled.

In Private Letter Ruling 89-51-069,[14] the IRS held that a subsidiary oil and gas producer could remain "independent" for purposes of Code section 613A despite the creation of affiliate retailer corporations. In this case, an affiliated group of corporations produced and sold oil and gas. None were considered a retailer under section 613A(d)(2). The parent company created an additional subsidiary designed to sell oil products to commercial or industrial end users. Sales estimates for the subsidiary exceeded $5 million per year. There was to be no relationship between the new subsidiary and the third party buyers of the oil and gas products. Further, no corporation in the group

12. Rev. Rul. 90-62, 1990-2 C.B. 158.
13. Priv. Ltr. Rul. 90-14-024 (January 3, 1990).
14. Priv. Ltr. Rul. 89-51-069 (September 28, 1989).

would sell oil, gas or other derivative products to any person having an obligation to sell those products to the new subsidiary. Both the oil and gas producing subsidiary and the new subsidiary would trade in the stream of commerce at market prices. Given the separation of the affiliates, the Service determined that the oil and gas producing subsidiary would continue to qualify as an independent producer for purposes of section 613A.

B. Section 29: Energy Credit

1. IRS Rulings

In four private letter rulings,[15] the IRS held that gas produced between 1980 and the end of 1990 through recompletions and completions from sideways extensions of pre-1980 wellbores qualified for credit under Code section 29(f)(1)(A)(i). Section 29 provides an income tax credit for certain fuels produced from wells, which absent the credit, might not otherwise be economical to produce. At the time the four rulings were issued, section 29(f)(1)(A)(i) limited the credit to the production of qualified fuels from wells drilled after December 31, 1979, but before January 1, 1991.[16]

The Service found that recompletion and directional drilling completions qualified as a "wells drilled" because both methods affect the intended economic tapping of new reserves. The Service recognized that well drilling, recompletions and horizontal drilling all connote establishment of a new conduit which grants access to and allows withdrawal of the mineral resource. The IRS noted that if production is eligible for incentive price supports under the Natural Gas Policy Act,[17] such eligibility supports a determination that the production qualifies for the credit, which is the perceived alternative subsidy to incentive pricing.

The IRS also clarified that if a well was "spudded-in" before January 1, 1991, and there is continual drilling until the production horizon is reached, the well is considered to have been drilled before January 1, 1991, for the purposes of section 29.[18] In this case, the taxpayer was involved in exploration, development, drilling, production and marketing of natural gas and oil, and the extraction and sale of natural gas liquids. The taxpayer planned to drill several wells in Devonian shale formations during 1990, but would not complete the project before January 1, 1991. The IRS stated that suspension of drilling operations just above the production horizon under the open-hole completion method would not be considered a termination of continual drilling. Furthermore, drilling would be considered to be continual even when delays occur if the delays resulted from factors beyond the taxpayer's control.

15. Priv. Ltr. Rul. 90-33-007 (May 15, 1990); Priv. Ltr. Rul. 90-25-002 (March 2, 1990); Priv. Ltr. Rul. 90-27-005 (March 26, 1990); Priv. Ltr. Rul. 90-35-034 (June 1, 1990).

16. The 1990 Act extended this date to January 1, 1993. § 11501, 104 Stat. 1388, 1388—479-80.

17. Natural Gas Policy Act of 1978, 15 U.S.C. § 3301-432 (1988).

18. Rev. Rul. 90-70, 1990-2 C.B. 3.

C. *Section 461 Deductions*

In *Lebowitz v. Commissioner*,[19] the United States Court of Appeals for the Second Circuit reversed the Tax Court and allowed a limited partner to deduct interest expenses and prorata losses in a coal mining partnership, even though the operation had gone into default. The taxpayer in this case was a limited partner in a coal mining partnership in December 1976. The partnership subleased property in West Virginia from Coats Run Energy Inc. (Coats Run). The partnership acquired the rights to mine the coal in exchange for $1.2 million in cash and a $4.15 million nonrecourse note. Although mining began in 1979 and continued through 1984, Coats Run went bankrupt before paying the limited partnership the royalty payments due. In 1983, with all of the parties in default, Coats Run, the limited partnership and co-owners of the property executed an agreement not to enforce claims against each other.

The limited partnership claimed a deduction in the amount of $5.35 million for the accrual of advanced royalties and an interest expense deduction in the amount of $41,500 on the nonrecourse note on its 1976 income tax return. In 1977, the limited partnership claimed an interest deduction in the amount of $249,000. The taxpayer claimed deductions for 1976 and 1977 for its prorata share of the losses attributable to the limited partnership.

The IRS disallowed the deductions and the Tax Court ruled that the taxpayer was not entitled to the deductions. The Tax Court held that while the limited partnership had entered into the lease with a profit motive, the project risks were so great that the nonrecourse note failed the "all events" test for deductibility.

The Second Circuit reversed the Tax Court's decision. It held that the nonrecourse obligation was genuine; thus, the interest was deductible. It agreed with the taxpayer that the proper question concerning the genuineness of the debt was whether the fair market value of the acquired asset approximates the amount of the nonrecourse note, not whether it approximated the entire purchase price. The court also held that events after the time of purchase affecting the value of the security were irrelevant for determining whether the nonrecourse obligation was genuine. Further, the court found that the debt was not contingent because the property had a determinable value and the limited partnership held a perpetual interest in the coal rights.

D. *Diesel Fuel: Final Regulations Under Section 4041*

The IRS issued final regulations[20] which allow qualified diesel fuel retailers to elect to shift the liability for the diesel fuel excise tax to the taxpayer who sold the fuel to the retailer, *i.e.*, the manufacturer. The final regulations are identical to the proposed temporary regulations issued in the Federal Register on March 1, 1988.[21] In the final rule, the Service said that it considered the regulations to be interpretative, and that the notice and comment proce-

19. 917 F.2d 1314 (2d Cir. 1990).

20. Treas. Reg. § 48.4041-21(g), (h)(1), (h)(2), (i)(3) and (k)(1) (T.D. 8303, 1990-2 C.B. 218).

21. Prop. Treas. Reg. § 48.4041-21T, 53 Fed. Reg. 6518 (1988).

dures under section 553 of the Administrative Procedure Act[22] did not apply.

E. Alcohol Fuels Credit

The IRS issued final regulations which define "mixture" under Code section 40 for purposes of the alcohol fuels credit and which are effective for sales or uses after September 30, 1980.[23] The final regulations provide that a product is considered to be a mixture of alcohol and gasoline or a mixture of alcohol and a special fuel within the meaning of section 40(b)(1)(B) if such product is produced by blending a chemical compound derived from alcohol with gasoline or a special fuel, so long as there is no significant loss of energy content of the alcohol. The presence or absence of a chemical reaction does not affect eligibility for the credit. For example, ethanol used to produce ethyl tertiary butyl ether (ETBE) qualifies for the alcohol fuels credit, even if chemically transformed.

IV. REGULATED ELECTRIC AND GAS UTILITIES

A. Tax Normalization

1. IRS Rulings

In Private Letter Ruling 90-24-064,[24] the IRS held that it would not specify the tax rate which a utility should use in establishing a regulated rate for the 1987 tax year. In this case a regulated electric utility used the flow-through method to account for the benefits of accelerated depreciation. The utility initially used the actual tax depreciation deduction in calculating income tax expense for ratemaking purposes. In order to claim an accelerated cost recovery deduction under section 168 of the Code, the utility switched to normalization accounting. The company would use book depreciation in calculating ratemaking income tax expense under the normalization method. However, as a result of the change of normalization, the utility had a problem of unrecovered tax liabilities. Certain property had already been fully depreciated for tax purposes, but not for book purposes; thus, the company could not collect enough in rates to cover tax benefits previously flowed through to customers.

The utility proposed an adjustment by amortizing the difference in the basis of the fully depreciated property over the remaining useful life in the property, multiplied by the tax rate. This amount would be deemed to equal an additional tax liability and would be included in rate making as an income tax expense.

The Service concurred and held that the taxpayer could use either the current 34% corporate income tax or the 1987 composite rate of 40% and not violate the normalization requirements as long as the deferred tax reserve is not reduced to provide for any of the unrecovered tax liabilities. Whether or

22. 5 U.S.C. § 553 (1988).
23. Treas. Reg. § 1.40-1 (T.D. 8291, 1990-1 C.B. 3).
24. Priv. Ltr. Rul. 90-24-064 (March 20, 1990).

not the 34% or 40% rate is allowed depends upon the utility regulator. The Service suggested that the 40% rate would be best for rate making purposes.

In Private Letter Ruling 90-24-067,[25] the Service held that a regulated utility must use the 40% statutory corporate income tax rate for 1987 in computing taxes because this was the rate at which rate-making tax expense was computed. The Service concluded that this would comply with the normalization rules.

2. Proposed Regulations

The IRS issued proposed regulations on the application of the normalization requirements of Code sections 167(1) and 168(i)(9) for utility companies filing consolidated returns.[26] The regulations would establish the extent to which ratemaking adjustments based on tax savings attributable to the filing of a consolidated return would be considered to be consistent with tax normalization requirements. The regulations would provide that in order to comply with the normalization requirements, a utility's rate making tax expense should be determined as though it filed a separate return. The regulations are proposed to be effective for rate orders that become effective on or after December 19, 1990.

B. Energy Conservation Credit

Senator Symms (R-Idaho) introduced legislation which would allow public utility customers such as gas, electric and water utility consumers to exclude from gross income any subsidies paid by the utility to encourage the purchase of energy-saving services and appliances.[27] The bill would have overturned an IRS ruling that such subsidies are income. In an informal session, the Senate Finance Committee decided to take no further action on the bill.[28]

Representative Kennelly (D-Conn.) introduced similar legislation.[29] The legislation would have expanded the National Energy Conservation Policy Act of 1978[30] to allow industrial and commercial customers to qualify for the income exclusion, and it would have encouraged the installation of water conservation devices. The bill went to the House Ways and Means Committee and was not acted upon.

V. DEVELOPMENTS AFFECTING REGULATED ELECTRIC/QUALIFYING FACILITIES

A. Sections 48 and 49: Investment Credits

The Service issued two private letter rulings regarding the investment

25. Priv. Ltr. Rul. 90-24-067 (March 20, 1990).

26. Prop. Treas. Reg. §§ 1.167(l)-1(h)(7) and 1.168(i)-1, 55 Fed. Reg. 49294 (1990).

27. S. 2312, 101st Cong., 2d Sess., 136 CONG. REC. S2939-40 (1990).

28. Senator Symms reintroduced the bill in early 1991. S. 83, 102 Cong., 1st Sess., 137 CONG. REC. S726-27 (1991).

29. H.R. 4249, 101st Cong., 2d Sess., 136 CONG. REC. H753 (1990).

30. 42 U.S.C. § 8201-86 (1988).

credit tax effect of modifications to hydroelectric facilities or power purchase agreements. In Private Letter Ruling 86-28-033,[31] the IRS held that a hydroelectric facility which previously qualified for energy credits under Code section 48 may continue to qualify even though a second stage development is being built. In this case, the taxpayer had not sought an energy credit for the second stage development. The letter indicated that so long as the second stage of the project was not considered a new impoundment, the second stage development would not impair the existing energy credit.

In Private Letter Ruling 90-10-012,[32] the Service held that an amendment to a power purchase agreement will not necessarily affect the taxpayer's previous qualifications under the section 49 investment credit suspension. In a prior ruling[33] for the taxpayer, the Service found that a power purchase agreement for the sale of power generated by a group of self-contained power plants qualified for transitional relief under sections 204(a)(3) and 211(a) of the Tax Reform Act of 1986[34] (1986 Act) as property that is readily identifiable and necessary to carry out a written supply and service contract. Subsequently, the taxpayer amended the agreement, changing the timing and the amount of compensation for the services. The letter suggested that so long as the amendments did not substantially modify the agreement, the power purchase agreement would continue to satisfy the requirements of the service or supply contract transitional rules.

B. Nuclear Decommissioning

1. Rulings

In Private Letter Ruling 90-25-081,[35] which interpreted section 1.468A of the Income Tax Regulations, the IRS accepted a proposed alternative rate of return for decommission fund assets. The utility used a different assumed annual rate of return on its decommissioned funds than that approved by the public utility commission. The Service accepted the alternative rate of return, finding that the assumed rate of return was reasonable.

2. Proposed Regulations

The IRS issued proposed regulations[36] under Section 468A that would provide nuclear decommissioning reserve funds with two methods of pooling assets for investment purposes so as not to create a separate taxable entity which would violate the investment restrictions. Currently, the regulations do not state whether the pooling of assets creates a separate taxable entity and violates the direct investment requirement. The proposed regulations would apply to any pooling of assets of one or more qualified nuclear decommission-

31. Priv. Ltr. Rul. 86-28-033 (April 11, 1986).
32. Priv. Ltr. Rul. 90-10-012 (December 6, 1989).
33. Priv. Ltr. Rul. 89-24-038 (March 20, 1989).
34. Pub. L. No. 99-514, §§ 204 and 211, 100 Stat. 2085, 2146-70 (1986).
35. Priv. Ltr. Rul. 90-25-081 (March 28, 1990).
36. Prop. Treas. Reg. § 1.468A-5, 55 Fed. Reg. 26460 (1990).

ing funds as well as the pooling of one or more qualified nuclear decommissioning funds with one or more nonqualifying nuclear decommissioning funds.

Under the proposed regulations, any pooling of assets for investment purposes in a regulated investment company or a common trust fund will satisfy the investment requirements if the general investment and self-dealing restrictions applicable to all qualified nuclear decommissioning funds are met. The proposed regulations would be effective as of July 18, 1984.

C. *Section 204: ITC Qualifications*

In Private Letter Ruling 90-10-035,[37] the Service held that modifications to a power plant facility after the Federal Energy Regulatory Commission (FERC) certification do not affect the project's investment tax credit (ITC) qualification under section 204 of the 1986 Act.[38]

The taxpayer obtained the FERC certification of a facility qualifying as a small power production facility under the Public Utility Regulatory Policies Act of 1978 (PURPA).[39] Subsequently, the taxpayer filed an amendment to the application and the FERC recertified the project. The taxpayer then proposed additional changes which included a reduction in the number of boilers, the reduction of the BTU requirement, and the implementation of a two stage construction process.

The Service held that the proposed changes to the project would not affect the ITC qualification because it would not change the essential nature of the facility already certified. Therefore, the project qualified under section 204(a)(2)(A) of the 1986 Act for transition relief from modifications to the accelerated cost recovery system as well as transition relief from the repeal of the ITC under section 49(b) of the Code. The Service also ruled that sale of the facility before it was placed into service would not affect the facility's qualification under section 204(a)(2)(A) of the 1986 Act.

D. *Contribution in Aid of Construction*

In Notice 90-60,[40] the Service modified Notice 88-129,[41] which related to payments or transfers of property from qualifying small power producers and cogenerators (qualifying facilities) to regulated public utilities. Now, when a qualifying facility and a utility terminate power purchase agreements, the qualifying facility will be deemed to have made a transfer to the utility if the utility obtains or retains ownership of certain qualifying facility property for tax purposes. Thus, the utility is to include in income the fair market value of the property deemed transferred, less the amount paid by the utility. The fair market value of the property shall be determined by taking into account all facts and circumstances, including age and condition of the property and whether property is needed to serve the utility's customers.

---

37. Priv. Ltr. Rul. 90-10-035 (December 11, 1989).
38. Pub. L. No. 99-514, § 204, 100 Stat. 2085, 2146-65 (1986).
39. 16 U.S.C. § 2601-45 (1988).
40. I.R.S. Notice 90-60, 1990-2 C.B. 345.
41. I.R.S. Notice 88-129, 1988-2 C.B. 541.

Previously, under Notice 88-129, such a transfer was deemed to be a CIAC under Code section 118b. Notice 90-60 modifies section 4(B) of Notice 88-129 provided that a qualifying facilities property transfer will generally not be treated as a CIAC except where circumstances demonstrate that the parties intended to characterize a transfer as a qualifying facilities transfer when it was, in fact, a CIAC event.

Lee M. Goodwin, *Chairman*
Paul W. Hartley, *Vice Chairman*
Thomas F. DeCaro, Jr. Donegan Mann

* * *

Please note the correct committee members for the Natural Gas Certificate and Authorization Regulations Report in Vol. 12, No. 1.

Sherrie Nichols Rutherford, *Chair*
James F. Bowe, Jr., *Vice Chair*

Ernest B. Abbott	Judy M. Johnson
James H. Bailey	Douglas J. Law
Lee M. Beckett	Stuart Ian Levin
Susan J. Court	David J. Muchow
David L. Duplantier	Vera Callahan Neinast
Steve H. Finch	T. Luke Rogers
Robert Fleishman	Carol A. Smoots
Thomas C. Gorak	Jane E. Stelek
Joel L. Greene	Philip R. Telleen
Thomas E. Hirsch, III	James P. White