Report of the Committee on Tax Developments

I. Introduction

Aimed at promoting energy efficiency, conservation, and the development of nonconventional fuel sources, the tax provisions in Title XIX of the Energy Policy Act of 1992[1] culminated a year of notable tax developments bearing on all segments of the energy industry. These tax provisions of the Energy Policy Act are highlighted below, followed by a summary of 1992's judicial opinions and regulatory decisions and/or regulations issued by the Federal Energy Regulatory Commission (FERC) and the Internal Revenue Service (IRS) affecting (1) regulated electric utilities and natural gas companies; and (2) oil/natural gas production and the generation of electricity.

II. Major Tax Provisions of the Energy Policy Act of 1992

A. *Oil and Gas Drillers*

The provisions provide tax relief to independent oil and gas drillers from the Alternative Minimum Tax, as defined in section 55 of the Internal Revenue Code (IRC),[2] by permanently eliminating tax preferences with respect to intangible drilling costs and excess percentage depletion, as defined in IRC section 57. The elimination of such tax preferences is expected to cost the Treasury an estimated one billion dollars over five years.

B. *Nonconventional Fuels*

The nonconventional fuel tax credit authorized under IRC section 29, governing the production of fuel from nonconventional sources, to facilities which produce gas from biomass or which produce liquid, gaseous, or synthetic fuels from coal, if such facilities are placed in service prior to January 1, 1997, pursuant to a written, binding contract in effect prior to January 1, 1996. Section 29 does not extend the tax credit for gas produced from newly drilled tight formation wells.

C. *Renewable Energy*

Title XIX creates a production credit of 1.5 cents for every kilowatt hour of electricity generated by either of two renewable energy sources: 1) wind; 2) "closed-loop biomass" which consists of crops grown exclusively to produce electricity. The credit will be available for ten years after the renewable energy facility has been placed into service but will be phased-out if the price of electricity produced from the renewable energy sources exceeds a certain threshold. In addition, the Act permanently extends the energy investment credit for solar and geothermal property.

1. Pub. L. No. 102-486, 106 Stat. 2776 (October 24, 1992).
2. 26 U.S.C. § 55 (1988).

D. Alternative-Fueled Vehicles

The Act creates a tax deduction for persons purchasing alternative fuel-driven vehicles or related fueling equipment with the exception of electric vehicles that qualify for a new tax credit. Tax deductions are as follows:

1. for motor vehicles propelled by non-conventional fuels, a tax deduction of up to $2,000;
2. for motor vehicles propelled by either alternative or conventional fuels, a tax deduction equal to the "incremental cost of permitting the use of the clean-burning fuel."[3]
3. for trucks or vans weighing between 10,000 and 26,000 pounds, a tax deduction capped at $5,000;
4. for heavier trucks or vans, or for buses capable of seating at least 20 adults, a tax deduction capped at $50,000.

E. Electric Vehicle Credit

There is now a 10% tax credit for persons purchasing an electric vehicle. The credit is capped at $4,000 per vehicle and will be phased-out entirely in 2005.

F. Conservation Subsidies

Utilities will be permitted to exclude from their taxable income energy conservation subsidies (*i.e.*, rebates for buying or installing conservation equipment) provided to residential customers. While similar subsidies to commercial and/or industrial customers will be fully taxed as income through 1994, public utilities may exclude from income 40% of such subsidies in 1995, 50% in 1996, and 65% in 1997.

G. Nuclear Decommissioning

The Act encourages nuclear utilities to expend funds for decommissioning by repealing the investment restrictions applicable to nuclear decommissioning funds for 1993 and beyond, and by lowering the tax rate on earnings in a decommissioning fund to 22% in 1994 and 1995, and to 20% in 1996.

H. State Financing of Hydroelectric Enhancements

The Act encourages construction of improvements at hydroelectric dams by excluding the tax-exempt facility bonds used to finance such improvements from federal regulations that limit the number of tax-exempt bonds that each state may issue.

I. Tax Exemption For Ethanol-Blended Gasoline

The Act broadens the partial excise tax exemption for gasoline blended with ethanol or other alcohol.

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3. I.R.C. § 179A (1993).

III. Developments Affecting Regulated Electric Utilities And Natural Gas Companies

A. *Court Decisions*

1. *Roanoke Gas Company v. United States*[4]

The United States Court of Appeals for the Fourth Circuit, on October 1, 1992, affirmed the lower court's ruling that a gas utility's obligation to "refund" to its ratepayers prior gas cost overcollections by means of future rate reductions is not a deductible business expense, but rather constitutes a regulated reduction of income. In *Roanoke*, the affected utility routinely "tracked" its purchased gas costs through a purchased gas adjustment mechanism, and reconciled its actual gas costs with estimated gas costs, upon which ratepayers' rates were based, on an annual basis. Any overrecoveries or underrecoveries during one year were refunded to, or recovered from, ratepayers through a rate adjustment the following year.

Commencing in 1987, in accordance with the Virginia State Corporation Commission's directives, the utility, for accounting purposes, deducted from income overcollections in the year in which its gas costs were less than the rates charged to ratepayers rather than recognizing less income the following year when rates were reduced through the utility's rate adjustment mechanism.[5] To reconcile its accounting and federal income tax treatment of gas cost collections, the utility recomputed its tax liability for the years 1984-86, applying the accounting principles dictated by the Corporation Commission. Such recomputations resulted in a significant increase in claimed tax deductions for the period 1984-86, and, in turn, yielded more than $2 million in claimed tax refunds for those years. Agreeing with the lower court that the utility erred in claiming the subject deductions, the Fourth Circuit rejected the utility's argument that its gas cost overcollections during the period 1984-86 constituted fixed liabilities which satisfied the "all events" test,[6] and thus were deductible in the taxable year(s) during which such amounts were collected. Concentrating on the means by which the utility "refunded" overcollections to ratepayers, the rate adjustment mechanism, the court reasoned that such mechanism did not establish a legal obligation to pay, inasmuch as "[n]o payment is ever made, . . . no credit is shown on any customer's bill . . . [and no] effort is made to match "refunds" with persons who overpaid or to assure that those who did not overpay do not receive refunds."[7] Rather, the rate adjustment, "applying to all sales of gas regardless of whether the customer was overcharged," merely "implemente[d] a policy to allocate income on the books of the utility to a given year in order to match income and costs more

4. 977 F.2d 131 (4th Cir. 1992).

5. Similarly, the utility treated undercollections as income for the year in which the undercollections accrued (*i.e.*, the year in which its gas costs exceeded the rates charged to ratepayers, instead of the year in which rates were increased to recover the undercollections).

6. As the court in Roanoke stated, under the "all events" test, set forth in Treas. Reg. 1.461-1(a)(2), an expense incurred under the accrual method of accounting is deductible for the taxable year in which "all the events have occurred which determine the fact of the liability and the amount thereof can be determined with reasonable accuracy."

7. *Roanoke*, 977 F.2d at 136.

accurately."[8] Accordingly, the utility's obligation in year one to reduce rates in year two (or later) did not qualify as a tax-deductible business expense.

2. *United States v. Delaware*[9]

On March 12, 1992, the Third Circuit reversed the district court's judgment in favor of the State of Delaware, and held that a state utility tax assessed against an electric utility and "mandatorily passed on" by the utility to the United States, Dover Air Force Base, as a consumer of electricity, was a direct tax on the United States, and, as such, was unconstitutional per se as violative of the intergovernmental tax immunity doctrine implied in the Supremacy Clause.[10] Based on the language of the relevant state statute, the court concluded that the state's taxing authorities intended to establish "mandatory passthroughs" of the subject utility tax. The court rejected the state's contention that the "legal incidence" of the tax fell on the affected electric utility and that the United States bore only the indirect "economic burden" of the tax.

3. *Southwestern Public Service Co. v. FERC*;[11] *Southwestern Public Service Co.*[12]

On January 14, 1992, the United States Court of Appeals for the District of Columbia remanded to the FERC two orders issued in 1987 in which the FERC had required a jurisdictional utility to make a post-test period adjustment to its wholesale rates to reflect a reduction in the federal corporate income tax rate from 46% to 34%. While finding that the FERC had not acted arbitrarily in ordering the utility to make a "spot adjustment" to its estimated costs, and thus its effective rates, to reflect the lower tax expense resulting from the tax change, the court questioned the FERC's failure to consider whether the required spot adjustment was offset by a commensurate post-test period increase in the utility's purchased power costs. Accordingly, the court directed the FERC, on remand, to "address the question of whether the [utility's] customers have shown that, despite the [utility's increased purchased power] costs, the . . . tax rate change rendered [the utility's] rates unreasonable."[13]

In its order on remand issued July 21, 1992,[14] the FERC, relying on the "specific and unique circumstances of this case,"[15] re-opened the record and established hearing procedures to consider "all post test-period changes" to

8. *Id.*
9. 958 F.2d 555 (3rd Cir. 1992).
10. McCulloch v. Maryland, 17 U.S. (4 Wheat.) 316 (1819).
11. 952 F.2d 555 (D.C. Cir. 1992).
12. 60 F.E.R.C. ¶ 61,052 (1992).
13. 952 F.2d at 563.
14. 60 F.E.R.C. ¶ 61,052 (1992).
15. *Id.* at 61,189. The "specific and unique circumstances" cited by the FERC included "a Congressionally-mandated, statutory change in the federal corporate income tax rate that comes after the close of the record, the Court's remand ordering the Commission to consider other post-test period changes to estimated costs; the fact that the availability of actual data makes litigation of test-year estimates counterproductive; and the fact that the rates at issue are for a locked-in [*i.e.*, past] period."

the utility's cost-of-service, "including, but not limited to, the tax rate change and the alleged purchased power cost increase."[16] However, the FERC clarified that the rates ultimately established "may be no higher than the rates initially proposed by [the utility] and may be no lower than the rates in effect at the time [the utility] filed the proposed rate increase in this proceeding."[17]

B. FERC Orders

1. Post-Retirement Benefits Other Than Pensions

On December 17, 1992, the FERC issued a Policy Statement[18] regarding the rate treatment of post-retirement benefits other than pensions (PBOPs), such as medical benefits for current employees of natural gas companies and public utilities subject to the FERC's jurisdiction. The policy statement applies to jurisdictional oil pipeline companies only to the extent that they elect to adhere to it. In response to recent filings by companies seeking to conform their ratemaking treatment of PBOPs with their accounting treatment of such expenses,[19] the FERC authorized jurisdictional natural gas companies and utilities to include accrued costs of PBOPs in current rates rather than expensing PBOP amounts for rate purposes when such amounts are actually paid to covered retirees. However, the FERC qualified its approval of the "accrual method" by attaching specific conditions to a company's use of such method, namely: (1) The company must agree to fund PBOPs by depositing cash, no less frequently than quarterly, to an irrevocable external trust[20]; and (2) The company must agree to maximize the use of income tax deductions for contributions to the trust. For that portion of the funded amount which is not currently tax deductible, certain tax deductible funding arrangements[21] may preclude companies from taking a current deduction for the entire amount they are required to contribute to the trusts during one year. Thus, the company must follow deferred income tax accounting. However, the company may include the resulting accumulated deferred tax balance in its jurisdictional rate base until timing differences are resolved.

16. *Id.* at 61,188-189. Because the affected rate proceeding governed rates that had been superseded by revised rates implemented pursuant to a separate rate filing, the FERC directed the utility to file an updated cost-of-service using actual (rather than estimated) costs (except for return on equity), actual allocation factors, and actual billing determinants.

17. *Id.* at 61,189.

18. 61 F.E.R.C. ¶ 61,330 (1992).

19. *See, e.g.*, New England Power Co., 61 F.E.R.C. ¶ 61,331 (1992). In December 1990, the Financial Accounting Standards Board (FASB) issued FASB 106, which requires employers, for fiscal years after December 15, 1992, to reflect in current expense an accrual for post-retirement benefits other than pensions during the working years of covered employees.

20. The monies in such trust must equal, on an annual basis, the company's annual test-period allowance for PBOPs.

21. Under the Deficit Reduction Act of 1984, PBOP amounts paid into an external trust for collective bargaining employees are deemed operating expenses, deductible from income for tax purposes.

C. *IRS Rulings*

1. Treatment of Property Transferred to Utility

In Letter Ruling (LTR) 92-24-054,[22] the IRS ruled that where an interstate natural gas pipeline constructed and transferred ownership of certain pipeline facilities to a regulated public utility "exclusively in connection with" the pipeline's sale of natural gas to the utility, and where the cost of such facilities was not included in the utility's rate base, the transfer of ownership was not a "contribution in aid of construction" under IRC section 118(b), and thus was not taxable to the utility.[23] Similarly, in LTR 92-11-030,[24] the IRS ruled that where an independent power producer paid two public utilities with which it had executed power purchase agreements the costs of constructing interconnection and transmission facilities needed to effectuate the agreements, and where the costs were not included in the utilities' rate bases, the transfer of cash to the utilities was not a "contribution in aid of construction" under IRC section 118(b).

2. Utility Gross Income

In four Letter Rulings (LTRs 92-18-026,[25] 92-18-027,[26] 92-18-031,[27] and 92-15-054[28]), the IRS ruled that a state-regulated utility may exclude from income the refunds it receives from its suppliers that are attributable to reductions in the suppliers' rates, resulting from federally-mandated rate reductions, where the utility passes on the refunds to its ratepayers through rate adjustments. In addition, the IRS ruled that certain funds that the utility receive from a state-operated trust to finance the construction of facilities would be treated as "contributions to the capital" under IRC section 118(a), and thus excluded from gross income, rather than "any contribution in aid of construction" under IRC section 118(b).

3. Electric Utility's Local System Facilities

In LTR 92-27-030,[29] the IRS ruled that a "border accommodation" power transmission arrangement entered into between an electric utility and a separate entity in another county, pursuant to which the latter constructed and connected directly to the utility's facilities low-voltage distribution lines, did not alter the status of the utility's facilities as "facilities for the local furnishing of electric energy" under Treasury regulation § 1.103-8(f)(2)(iii). Accordingly, the utility was not required to include in gross income its interest

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22. Priv. Ltr. Rul. 92-24-054 (March 19, 1992).

23. Under IRC § 118(a) (1992), a corporation's gross income does not include contributions to capital. *See* IRC § 118(a) (1992). However, § 118(b) provides that contributions to capital do not include any "contribution in aid of construction or any other contribution as a customer or potential customer," which contributions are includable in gross income. *See* IRC § 118(b) (1992).

24. Priv. Ltr. Rul. 92-11-030 (Dec. 16, 1991).

25. Priv. Ltr. Rul. 92-18-026 (Jan. 28, 1992).

26. Priv. Ltr. Rul. 92-18-027 (Jan. 28, 1992).

27. Priv. Ltr. Rul. 92-18-031 (Jan. 28, 1992).

28. Priv. Ltr. Rul. 92-15-054 (Jan. 16, 1992).

29. Priv. Ltr. Rul. 92-27-030 (Apr. 7, 1992).

on state and local bonds under IRC section 103(b)(1). The IRS reasoned that the border accommodation was incidental to the utility's business of providing adequate and efficient electric service to retail ratepayers, and that the charges paid by such ratepayers would reflect only those costs attributable to the utility's provision of service within the retail area.

4. Investment Tax Credit Limitation Under IRC Section 46(f)(2)

In LTR 92-14-033,[30] the IRS ruled that a public utility's treatment of its nuclear plant investment for ratemaking purposes, as approved by the utility's state regulatory commission, involved neither a reduction in the utility's cost-of-service or regulated books of account under IRC section 46(f)(2)(A), nor a reduction in the utility's rate base under IRC section 46(f)(2)(B). Thus, the utility which had elected the "immediate flow-through" treatment of investment tax credits under IRC section 46(f)(2) was not subject to the limitations on the availability of such credits prescribed under section 46(f)(2).

The utility had included in its rate base one-half of its investment in the subject nuclear plant while absorbing the other half, and had retained all investment tax credits generated by the plant not previously flowed through to ratepayers. The IRS reasoned that the regulatory commission's rate order specifically precluded the utility from recovering the costs excluded from its rate base by flowing through the unamortized investment credits to income, thereby decreasing its cost-of-service for ratemaking purposes. Thus, there was no cost-of-service reduction for purposes of IRC section 46(f)(2).

IV. Developments Affecting Oil & Gas Production and Electricity Generation

A. *Court Opinions*

1. *Enron Oil and Gas Co. v. Lujan*[31]

The Fifth Circuit ruled that the Department of Interior (DOI), as lessor of certain federal lands leased for oil and gas production, properly included state severance tax reimbursements received by the producer/lessee, from purchasers of gas produced from the subject leases in the calculation of the producer/lessee's "gross proceeds," for purposes of computing royalties owed to the DOI by the producer/lessee.[32] Following earlier decisions,[33] the court rejected the producer/lessee's claim that the inclusion of tax reimbursements in the calculation of royalty payments, a longstanding practice of DOI, violates the Natural Gas Policy Act by preventing the producer/lessee from

30. Priv. Ltr. Rul. 92-14-033 (Dec. 20 1991).

31. 978 F.2d 212 (5th Cir. 1992).

32. The Secretary of Interior must collect royalties, at a minimum, of 12.5% of the "value of production removed or sold from the lease." 30 U.S.C. § 226(b) (1992). Under DOI regulations, the "value of production" cannot be less than "the gross proceeds accruing to the lessee from the sale" of production under the subject lease. 30 C.F.R. § 206.103(1992).

33. *See* Mesa Operating Ltd. Partnership v. DOI, 931 F.2d 318, 325 (5th Cir. 1991); Hoover & Bracken Energies v. DOI, 723 F.2d 1488, 1492 (10th Cir. 1983), *cert. denied*, 469 U.S. 821 (1984).

receiving the maximum lawful price for its leasehold production "undiluted" by state severance taxes.

2. *Shell Oil Co. v. Commissioner*[34]

Addressing how "net income from the property" should be calculated for purposes of determining an oil company's windfall profit tax liability under the Crude Oil Windfall Profit Tax of 1980,[35] the court held that abandoned geological and geophysical (G&G) costs incurred by the oil company were an indirect cost to the company's mineral properties, and were an allowable deduction, attributable "to the mining process," in calculating taxable income subject to the windfall profit tax. In addition, noting that the abandoned G&G costs should be apportioned among the oil company's several mineral properties pursuant to a "proper" apportionment formula because such costs were not directly attributable to a specific property, the court remanded the case to the tax court to consider whether the apportionment method utilized by the company was proper.

3. *Landreth v. United States*[36]

The Fifth Circuit, on June 18, 1992, held that a "net profit" interest owner in certain oil properties was not entitled to deduct, for purposes of determining taxable income subject to a windfall profit tax under the Crude Oil Windfall Profit Tax Act, either the amounts the operator of the properties charged it for windfall profit tax, which are the amounts the operator paid to the IRS, or the operator's charges for prior tax period operating expenses, both of which were assessed pursuant to contract. The interest owner, a cash-method taxpayer, had claimed that because it received no cash distributions in 1981, 1982 and 1983 on its net profits interest in the subject oil properties, it had no gross and thus no net income for purposes of computing income subject to the windfall profit tax, and, as a result, could have no windfall tax liability. Acknowledging that the interest owner received no cash distributions during the relevant time period, the court nonetheless relied on the IRC provisions governing the computation of the windfall profit tax (as well as the Treasury regulations promulgated thereunder) to reject the interest owner's claim.[37]

4. *Transco Exploration Co. v. Commissioner*[38]

On January 7, 1992, the Fifth Circuit held that an oil and gas explora-

34. 952 F.2d 885 (5th Cir. 1992).

35. From March 1, 1980, until its repeal effective August 23, 1988, the Crude Oil Windfall Profit Tax Act of 1980 imposed an excise tax on the taxable windfall profit from domestically produced crude oil. To prevent production from being taxed beyond the point of profitability, the Act included a provision, dubbed the "net income limitation," which effectively capped taxable windfall profit at 90% of the net income from the property.

36. 963 F.2d 84 (5th Cir. 1992).

37. Specifically, the court relied on IRC § 4988(b)(3)(B) in ruling on the deductibility of the windfall profit tax, and on § 4888(b)(2) in ruling on the deductibility of operating expenses from previous periods.

38. 949 F.2d 837 (5th Cir. 1992).

tion/production company which leased certain offshore properties from the federal government was entitled to "double deductions" with respect to certain lease bonus payments the company made to the federal government (as lessor) in tax year 1980. Relying on IRC sections 4988(b) and 613(a) and the Treasury regulations promulgated thereunder, which establish the windfall profit tax base and the ceiling limitation thereon, the court found that the company was entitled (1) to exclude $10.1 million in lease bonus payments from gross income in calculating the net income limitation on its windfall profit tax for tax year 1980; and (2) to include that same $10.1 million in its cost basis for purposes of computing the cost depletion deduction applicable to the property in 1980.

5. *Sealy Power, Ltd. v. Commissioner*[39]

The Tax Court sustained the IRS's determination that Sealy Power, a limited partnership formed to build and operate an electric power production facility, could not claim depreciation deductions, biomass energy tax credits, or investment tax credits for such facility in either 1983 or 1984, inasmuch as the partnership was unable to show that the facility was placed in service in either of those tax years. According to the court, a facility is placed in service and thus eligible for associated tax benefits when it becomes available for service on a regular basis. For instance, the entire facility must be functioning for its intended purpose. The subject facility, which operated only sporadically during 1983 and 1984, did not meet this criterion.

B. *FERC Orders*

1. FERC Order 539, Qualifying Certain Tight Formation Gas For Tax Credit[40]

Acting on a Notice of Proposed Rulemaking issued on March 20, 1991, the FERC issued a final rule on April 9, 1992, amending its regulations to conform to the Revenue Reconciliation Act of 1990. The Revenue Reconciliation Act, *inter alia*, (1) extended for two years the tax credit available under IRC section 29 for gas produced from newly-drilled tight formation wells;[41] and (2) revised the terms of eligibility to allow gas produced from tight formations to remain eligible for the section 29 tax credit even though the price for such gas was no longer regulated by virtue of the Natural Gas Wellhead Decontrol Act of 1989.[42]

39. T.C. Memo 1992-168,63 Tax Ct. Rep. (CCH) 2482 (1992).

40. III F.E.R.C. Stats. and Regs. ¶ 30,940 (1992).

41. Specifically, the Revenue Reconciliation Act extended the § 29 tax credit to gas produced from a well drilled (or a facility placed in service) before January 1, 1993, and sold before January 1, 2001. *See* IRC § 29(f)(1). In addition, the legislation provided that the § 29 credit would apply only to gas produced from a tight formation which was dedicated to interstate commerce as of April 20, 1977, or which was produced from a well drilled after the enactment of the Revenue Reconciliation Act. See IRC § 29(c)(2)(B).

42. Natural Gas Wellhead Decontrol Act of 1989, 15 U.S.C. § 3301 (1992). Prior to the Act, in order to qualify for the § 29 credit, gas from tight formations had to be subject to a specific maximum lawful price under the NGPA.

To carry out Congress' decision to restore the section 29 tax credit for tight formation gas produced from wells drilled before January 1, 1993, the FERC in Order 539 made one "conforming" amendment to 18 C.F.R. § 271.703. That section sets forth the eligibility criteria for tight formation status and thus incentive pricing under the NGPA.[43] Specifically, the FERC amended section 271.703(c)(2)(i)(B) to establish maximum stabilized production rates for gas produced from formations with an average depth of more than 15,000 feet.[44] Order 539 also clarifies that the FERC will continue its existing practice of using only the arithmetic averaging method in reviewing permeability data provided to it by jurisdictional state agencies in support of a tight formation designation; in short, the FERC found it unnecessary to revise its existing methodology to determine permeability in the face of complete wellhead decontrol effective January 1, 1993, pursuant to the Wellhead Decontrol Act of 1989.

2. *Phillips Petroleum Co. and Marathon Oil Co.*[45]

On March 16, 1992, the FERC dismissed a petition for declaratory order filed by two natural gas production companies regarding the proper determination of "gross value," for state tax purposes, of certain gas that companies produced in Alaska during the period December 1978 through December 1985.[46] The companies maintained that the taxable gross value of the production was limited to the maximum lawful price for such gas, as established by the FERC under the NGPA, inasmuch as the transfer of the gas at the wellhead from the companies' production divisions to their respective pipeline divisions constituted "first sales" under the NGPA, rendering the gas eligible for NGPA ceiling prices.[47] Thus, by their petition, the companies urged the FERC to issue an order declaring that the gas in question was subject to imputed NGPA maximum lawful prices during the relevant period.

Refusing to address the merits of the companies' petition, the FERC determined that a declaratory order would have "no regulatory significance," inasmuch as none of the issues raised by the petition affected any disputes concerning the FERC's "regulatory responsibilities" with respect to the companies. For instance, the price for the companies' gas was not at issue, nor

43. Under § 271.703, a formation must meet three standards to qualify as a tight formation: a maximum production rate for gas, a permeability standard, and an oil production volume limitation.

44. Because the price for gas produced from formations below 15,000 feet was deregulated on November 1, 1979, by the NGPA, the FERC had not previously established maximum production rates for such gas, finding it unnecessary to qualify unregulated gas for an incentive ceiling price. However, in light of the Revenue Reconciliation Act, which, as noted, extended the § 29 tax credit to tight formation gas no longer subject to price regulation, the FERC found it appropriate to "amend the regulations so that tight formations . . . below 15,000 feet may qualify for the tax credit."

45. 58 F.E.R.C. ¶ 61,290 (1992).

46. The State of Alaska imposes a tax on gas and oil produced within the state, which is based on the "gross value" of the gas or oil. Under state law, if the gross value of the production exceeds the maximum lawful price established by the FERC under the Natural Gas Policy Act, the gross value, for tax purposes, equals such maximum lawful price.

47. Conversely, the State of Alaska argued that the taxable gross value of the subject production equaled the sales price for such production in Japan (less costs), where the gas ultimately was transported.

were there any alleged violations of the NGPA.[48] According to the FERC, the underlying dispute was more properly resolved by an appropriate tax tribunal "without reaching any question within the [FERC's] exclusive jurisdiction."[49]

C. *IRS Rulings*

1. IRC Section 29 Nonconventional Fuel Tax Credit

The IRS issued a number of letter rulings in 1992 regarding the applicability of the section 29 tax credit. In LTR 92-30-017,[50] the IRS ruled that the "new production" limitation of IRC section 29(d)(4)[51] was not applicable to and thus did not render it ineligible for the section 29 credit for qualified fuels produced from wells in a new proration unit even though part of the acreage on the proration unit may have been part of an old proration unit from which qualified gas was produced in marketable quantities before January 1, 1980.

Similarly, in LTR 92-34-015,[52] the IRS ruled that the company's production from infill wells drilled on the undeveloped half of a proration unit would not be rendered ineligible for the section 29 credit by virtue of the "new production" limitation of IRC section 29(d)(4) solely because the company had produced gas from tight formation wells on the other half of the proration unit prior to January 1, 1980. In addition, the IRS ruled that the commingling of qualifying gas and "conventional" gas neither renders the former ineligible for the section 29 credit, nor qualifies the latter for such credit.[53]

In LTR 92-07-015,[54] the IRS ruled that the "new production" limitation of section 29(d)(4) did not apply to disqualify production from new wells within and near a federal exploratory unit which contained wells designated as tight formation wells prior to 1980. In allowing the section 29 credit, the IRS noted that the lack of communication within tight sands formations enabled the drainage area of each newly drilled well to exploit a part of the subject formation which had not previously been produced.

In LTR 92-21-034,[55] the IRS ruled that a company engaged in the production of electricity was not entitled to the section 29 credit where the company's operations showed that it had not sold "qualified fuel" to an unrelated person, as required by section 29(a). The company used biomass to produce heated gas, which, in turn, was used to produce the steam from which the electricity was generated. In rejecting the company's claim that it was entitled

48. In addition, the FERC reasoned that a declaratory order would not set "useful policy or precedent" in light of the fact that all natural gas production will be deregulated and thus no longer subject to NGPA maximum lawful prices, effective January 1, 1993, by virtue of the Wellhead Decontrol Act.

49. 58 F.E.R.C. ¶ 61,290, at 61,932 (1992).

50. Priv. Ltr. Rul. 92-30-017 (Apr. 27, 1992).

51. Section 29(d)(4), 26 U.S.C. § 29(d)(4), makes ineligible for the Section 29 credit production from a property from which qualified fuel was produced "in marketable quantities" prior to January 1, 1980.

52. Priv. Ltr. Rul. 92-34-015 (May 22, 1992).

53. Where gas produced from tight formations was commingled downstream with gas produced from conventional formations, the company proposed to allocate gas to the two formations according to a formula based on a production history approved by the appropriate state agency.

54. Priv. Ltr. Rul. 92-07-015 (Nov. 15, 1991).

55. Priv. Ltr. Rul. 92-21-034 (Feb. 12, 1992).

to the section 29 tax credit to the extent it sold the electricity to a third party, the IRS ruled that, in order to qualify for the tax credit, the company must sell to an unrelated person the gas produced from the biomass (not solely the electricity ultimately generated).

In LTR 92-22-047,[56] the IRS ruled that oil produced from a formation of shale rock does not qualify for the section 29 credit where the company proposed to drill into shale rock "in place," even though enhanced recovery methods were used. According to the IRS, the section 29 credit is available only for oil recovered, through "on-site retorting methods," from shale rock which has already been extracted.[57]

D. *IRS Regulations*

1. Enhanced Oil Recovery Credit[58]

On November 23, 1992, the IRS issued final regulations governing the tax credit available under IRC section 43 for certain costs paid or incurred in connection with a qualified enhanced oil recovery project. The revised regulations, *inter alia,* (1) retain the requirement that a taxpayer claiming the credit must own an operating mineral interest; (2) adopt specific revisions and/or clarifications to the "substantive expansion" exception to the "first injection" requirement for qualified enhanced oil recovery projects;[59] (3) describe the oil recovery methods that qualify as tertiary recovery methods subject to the section 43 credit; and (4) provide that only those amounts paid or incurred after December 31, 1990, for an asset which is used for the primary purpose of implementing an enhanced oil recovery project are "qualified enhanced oil recovery costs" subject to the section 43 credit.[60]

Eugene R. Elrod, *Chairman*
Gerald S. Endler, *Vice Chairman*

56. Priv. Ltr. Rul. 92-22-047 (Mar. 2, 1992).

57. *See also* Rev. Rul. 92-100, 1992-47 I.R.B. 5. Hydrocarbons existing naturally as liquids within a shale formation are ineligible for § 29 credit. Such credit applies only to liquid oils obtained when taxpayer retorts or otherwise processes shale.

58. 26 C.F.R. Pts. 1, 602 (1992).

59. To qualify as a "qualified enhanced oil recovery project," a project must meet, inter alia, a "first injection" requirement, i.e., the first injection of liquids, gases, or other matter for the project must occur after December 30, 1990. Under the amended regulations, a project for which a first injection occurred prior to January 1, 1991, is "significantly expanded" after December 31, 1990 (and thus may qualify for the § 43 credit as a "separate" enhanced oil recovery project) if it affects reservoir volume that was substantially unaffected by a project begun before January 1, 1991.

60. Thus, the final rule does not deny the § 43 credit for assets used primarily for tertiary recovery, but does deny the credit for assets used primarily for secondary or primary recovery.