CLEVELAND ELECTRIC ILLUMINATING CO
Form 10-Q
November 04, 2004

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D. C. 20549

FORM 10-Q

(Mark One)

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended September 30, 2004

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from _________ to _________

Commission File Number	Registrant; State of Incorporation; Address; and Telephone Number	I.R.S. Employer Identification No.
333-21011	FIRSTENERGY CORP. (An Ohio Corporation) 76 South Main Street Akron, OH 44308 Telephone (800)736-3402	34-1843785
1-2578	OHIO EDISON COMPANY (An Ohio Corporation) 76 South Main Street Akron, OH 44308 Telephone (800)736-3402	34-0437786
1-2323	THE CLEVELAND ELECTRIC ILLUMINATING COMPANY (An Ohio Corporation) c/o FirstEnergy Corp. 76 South Main Street Akron, OH 44308 Telephone (800)736-3402	34-0150020
1-3583	THE TOLEDO EDISON COMPANY (An Ohio Corporation) c/o FirstEnergy Corp. 76 South Main Street Akron, OH 44308	34-4375005

	Telephone (800)736-3402	
1-3491	**PENNSYLVANIA POWER COMPANY** **(A Pennsylvania Corporation)** **c/o FirstEnergy Corp.** **76 South Main Street** **Akron, OH 44308** **Telephone (800)736-3402**	**25-0718810**
1-3141	**JERSEY CENTRAL POWER & LIGHT COMPANY** **(A New Jersey Corporation)** **c/o FirstEnergy Corp.** **76 South Main Street** **Akron, OH 44308** **Telephone (800)736-3402**	**21-0485010**
1-446	**METROPOLITAN EDISON COMPANY** **(A Pennsylvania Corporation)** **c/o FirstEnergy Corp.** **76 South Main Street** **Akron, OH 44308** **Telephone (800)736-3402**	**23-0870160**
1-3522	**PENNSYLVANIA ELECTRIC COMPANY** **(A Pennsylvania Corporation)** **c/o FirstEnergy Corp.** **76 South Main Street** **Akron, OH 44308** **Telephone (800)736-3402**	**25-0718085**

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Indicate by check mark whether each of the registrants (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes [X] No [ ]

Indicate by check mark whether each registrant is an accelerated filer (as defined in Rule 12b-2 of the Act):

Yes [X] No [ ]	FirstEnergy Corp.
Yes [ ] No [X]	Ohio Edison Company, Pennsylvania Power Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company, Jersey Central Power & Light Company, Metropolitan Edison Company, and Pennsylvania Electric Company

Indicate the number of shares outstanding of each of the issuer s classes of common stock, as of the latest practicable date:

CLASS	OUTSTANDING AS OF NOVEMBER 4, 2004
FirstEnergy Corp., $.10 par value	329,836,276
Ohio Edison Company, no par value	100
The Cleveland Electric Illuminating Company, no par value	79,590,689
The Toledo Edison Company, $5 par value	39,133,887
Pennsylvania Power Company, $30 par value	6,290,000
Jersey Central Power & Light Company, $10 par value	15,371,270
Metropolitan Edison Company, no par value	859,500
Pennsylvania Electric Company, $20 par value	5,290,596

FirstEnergy Corp. is the sole holder of Ohio Edison Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company, Jersey Central Power & Light Company, Metropolitan Edison Company and Pennsylvania Electric Company common stock. Ohio Edison Company is the sole holder of Pennsylvania Power Company common stock.

This combined Form 10-Q is separately filed by FirstEnergy Corp., Ohio Edison Company, Pennsylvania Power Company, The Cleveland Electric Illuminating Company, The Toledo Edison Company, Jersey Central Power & Light Company, Metropolitan Edison Company and Pennsylvania Electric Company. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. No registrant makes any representation as to information relating to any other registrant, except that information relating to any of the FirstEnergy subsidiary registrants is also attributed to FirstEnergy Corp.

This Form 10-Q includes forward-looking statements based on information currently available to management. Such statements are subject to certain risks and uncertainties. These statements typically contain, but are not limited to, the terms anticipate , potential , expect , believe , estimate and similar words. Actual results may differ material to the speed and nature of increased competition and deregulation in the electric utility industry, economic or weather conditions affecting future sales and margins, changes in markets for energy services, changing energy and commodity market prices, replacement power costs being higher than anticipated or inadequately hedged, maintenance costs being higher than anticipated, legislative and regulatory changes (including revised environmental requirements), adverse regulatory or legal decisions and the outcome of governmental investigations (including revocation of necessary licenses or operating permits), availability and cost of capital, the continuing availability and operation of generating units, the inability to accomplish or realize anticipated benefits of strategic goals, the ability to improve electric commodity margins and to experience growth in the distribution business, the ability to access the public securities markets, further investigation into the causes of the August 14, 2003 regional power outages and the outcome, cost and other effects of present and potential legal and administrative proceedings and claims related to those outages, the final outcome in the proceeding related to FirstEnergy s Application for a Rate Stabilization Plan in Ohio, the risks and other factors discussed from time to time in the registrants Securities and Exchange Commission filings, including their annual report on Form 10-K (as amended) for the year ended December 31, 2003 and other similar factors. The registrants expressly disclaim any current intention to update any forward-looking statements contained in this document as a result of new information, future events, or otherwise.

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GLOSSARY OF TERMS

The following abbreviations and acronyms are used in this report to identify FirstEnergy Corp. and its current and former subsidiaries:

ATSI	American Transmission Systems, Inc., owns and operates transmission facilities
Avon	Avon Energy Partners Holdings
CEI	The Cleveland Electric Illuminating Company, an Ohio electric utility operating subsidiary
CFC	Centerior Funding Corporation, a wholly owned finance subsidiary of CEI
Companies	OE, CEI, TE, Penn, JCP&L, Met-Ed and Penelec
Emdersa	Empresa Distribuidora Electrica Regional S.A.
EUOC	Electric Utility Operating Companies (OE, CEI, TE, Penn, JCP&L, Met-Ed, Penelec, and ATSI)
FENOC	FirstEnergy Nuclear Operating Company, operates nuclear generating facilities
FES	FirstEnergy Solutions Corp., provides energy-related products and services
FESC	FirstEnergy Service Company, provides legal, financial, and other corporate support services
FGCO	FirstEnergy Generation Corp., operates nonnuclear generating facilities
FirstCom	First Communications, LLC, provides local and long-distance telephone service
FirstEnergy	FirstEnergy Corp., a registered public utility holding company
FSG	FirstEnergy Facilities Services Group, LLC, the parent company of several heating, ventilation air conditioning and energy management companies
GLEP	Great Lakes Energy Partners, LLC, an oil and natural gas exploration and production venture
GPU	GPU, Inc., former parent of JCP&L, Met-Ed and Penelec, which merged with FirstEnergy on November 7, 2001
GPU Capital	GPU Capital, Inc., owned and operated electric distribution systems in foreign countries
GPU Power	GPU Power, Inc., owned and operated generation facilities in foreign countries
GPUS	GPU Service Company, previously provided corporate support services
JCP&L	Jersey Central Power & Light Company, a New Jersey electric utility operating subsidiary
JCP&L Transition	JCP&L Transition Funding LLC, a Delaware limited liability company and issuer of transition bonds
MARBEL	MARBEL Energy Corporation, previously held FirstEnergy s interest in GLEP
Met-Ed	Metropolitan Edison Company, a Pennsylvania electric utility operating subsidiary
MYR	MYR Group, Inc., a utility infrastructure construction service company
NEO	Northeast Ohio Natural Gas Corp., formerly a MARBEL subsidiary
OE	Ohio Edison Company, an Ohio electric utility operating subsidiary
OE Companies	OE and Penn
Ohio Companies	CEI, OE and TE
Penelec	Pennsylvania Electric Company, a Pennsylvania electric utility operating subsidiary
Penn	Pennsylvania Power Company, a Pennsylvania electric utility operating subsidiary of OE
PNBV	PNBV Capital Trust, a special purpose entity created by OE in 1996
Shippingport	Shippingport Capital Trust, a special purpose entity created by CEI and TE in 1997
TE	The Toledo Edison Company, an Ohio electric utility operating subsidiary
TEBSA	Termobarranquilla S.A., Empresa de Servicios Publicos
TECC	Toledo Edison Capital Corporation, a 90% owned subsidiary of TE

The following abbreviations and acronyms are used to identify frequently used terms in this report:

ALJ	Administrative Law Judge
AOCL	Accumulated Other Comprehensive Loss
APB	Accounting Principles Board
APB 25	APB Opinion No. 25, Accounting for Stock Issued to Employees
ARB 51	Accounting Research Bulletin No. 51, Consolidated Financial Statements
ARO	Asset Retirement Obligation
ASLB	Atomic Safety and Licensing Board
BGS	Basic Generation Service
CO_2	Carbon Dioxide
CTA	Currency Translation Adjustment
CTC	Competitive Transition Charge
ECAR	East Central Area Reliability Agreement
EITF	Emerging Issues Task Force
EITF 03-1	EITF Issue No. 03-1, The Meaning of Other-Than-Temporary and Its Application to Certain Investments
EITF 03-16	EITF Issue No. 03-16, Accounting for Investments in Limited Liability Companies
EITF 99-19	EITF Issue No. 99-19, Reporting Revenue Gross as a Principal versus Net as an Agent

GLOSSARY OF TERMS, Cont.

EPA	Environmental Protection Agency
FASB	Financial Accounting Standards Board
FCON 7	FASB Concepts Statement No. 7, Using Cash Flow Information and Present Value in Accounting Measurements
FERC	Federal Energy Regulatory Commission
FIN	FASB Interpretation
FIN 46R	FIN 46 (revised December 2003), Consolidation of Variable Interest Entities
FMB	First Mortgage Bonds
FSP	FASB Staff Position
FSP EITF 03-1-1	FASB Staff Position No. EITF Issue 03-1-1, Effective Date of Paragraphs 10-20 of EITF Issue No. 03-1, *The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments*
FSP 106-1	FASB Staff Position No.106-1, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003
FSP 106-2	FASB Staff Position No.106-2, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003
GAAP	Accounting Principles Generally Accepted in the United States
HVAC	Heating, Ventilation and Air-conditioning
IRS	Internal Revenue Service
ISO	Independent System Operator
KWH	Kilowatt-hours
LOC	Letter of Credit
MACT	Maximum Achievable Control Technologies
Medicare Act	Medicare Prescription Drug, Improvement and Modernization Act of 2003
MISO	Midwest Independent System Operator, Inc.
Moody s	Moody s Investors Service
MTC	Market Transition Charge
MTN	Medium Term Note
MW	Megawatts
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Council
NJBPU	New Jersey Board of Public Utilities
NOV	Notices of Violation
NO_X	Nitrogen Oxide
NRC	Nuclear Regulatory Commission
NUG	Non-Utility Generation
OCC	Ohio Consumers Counsel
OCI	Other Comprehensive Income
OPEB	Other Post-Employment Benefits
PCAOB	Public Company Accounting Oversight Board (United States)
PJM	PJM Interconnection ISO
PLR	Provider of Last Resort
PPUC	Pennsylvania Public Utility Commission
PRP	Potentially Responsible Party
PUCO	Public Utilities Commission of Ohio
PUHCA	Public Utility Holding Company Act

RTC	Regulatory Transition Charge
S&P	Standard & Poor s Ratings Service
SBC	Societal Benefits Charge
SEC	United States Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards
SFAS 71	SFAS No. 71, Accounting for the Effects of Certain Types of Regulation
SFAS 87	SFAS No. 87, Employers Accounting for Pensions
SFAS 95	SFAS No. 95, Statement of Cash Flows
SFAS 106	SFAS No. 106, Employers Accounting for Postretirement Benefits Other Than Pensions
SFAS 123	SFAS No. 123, Accounting for Stock-Based Compensation
SFAS 128	SFAS No. 128, Earnings per Share
SFAS 133	SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities
SFAS 140	SFAS No. 140, Accounting for Transfers and Servicing of Financial Assets and Extinguishment of Liabilities
SFAS 142	SFAS No. 142, Goodwill and Other Intangible Assets
SFAS 143	SFAS No. 143, Accounting for Asset Retirement Obligations

GLOSSARY OF TERMS, Cont.

SFAS 144	SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets
SFAS 150	SFAS No. 150, Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
SPE	Special Purpose Entity
TBC	Transition Bond Charge
TMI-1	Three Mile Island Unit 1
TMI-2	Three Mile Island Unit 2
VIE	Variable Interest Entity

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PART I. FINANCIAL INFORMATION

FIRSTENERGY CORP. AND SUBSIDIARIES
OHIO EDISON COMPANY AND SUBSIDIARIES
THE CLEVELAND ELECTRIC ILLUMINATING COMPANY AND SUBSIDIARIES
THE TOLEDO EDISON COMPANY AND SUBSIDIARY
PENNSYLVANIA POWER COMPANY AND SUBSIDIARY
JERSEY CENTRAL POWER & LIGHT COMPANY AND SUBSIDIARIES
METROPOLITAN EDISON COMPANY AND SUBSIDIARIES
PENNSYLVANIA ELECTRIC COMPANY AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

1 - ORGANIZATION AND BASIS OF PRESENTATION:

The principal business of FirstEnergy is the holding, directly or indirectly, of all of the outstanding common stock of its eight principal electric utility operating subsidiaries: OE, CEI, TE, Penn, ATSI, JCP&L, Met-Ed and Penelec. Penn is a wholly owned subsidiary of OE. JCP&L, Met-Ed and Penelec were acquired in a merger (which was effective November 7, 2001) with GPU, the former parent company of JCP&L, Met-Ed and Penelec. The merger was accounted for by the purchase method of accounting and the applicable effects were reflected on the financial statements of JCP&L, Met-Ed and Penelec as of the merger date. FirstEnergy s consolidated financial statements also include its other principal subsidiaries: FENOC, FES and its subsidiary FGCO, FESC, FirstCom, FSG, GPU Capital, GPU Power and MYR.

FirstEnergy and its subsidiaries follow GAAP and comply with the regulations, orders, policies and practices prescribed by the SEC, FERC and, as applicable, PUCO, PPUC and NJBPU. The consolidated unaudited financial statements of FirstEnergy and each of the Companies reflect all normal recurring adjustments that, in the opinion of management, are necessary to fairly present results of operations for the interim periods. Certain prior year amounts have been reclassified to conform with the current year presentation. In particular, expenses (including transmission and congestion charges) were reclassified among purchased power, other operating costs and depreciation and amortization to conform with the current year presentation of generation commodity costs. As discussed in Note 8, segment reporting in 2003 was reclassified to conform with the current year business segment organizations and operations. In addition, revenues, expenses and taxes related to certain divestitures in 2003 have been reclassified and reported net as discontinued operations (see Note 2) and certain revenues and expenses have been reclassified and presented on a net basis to conform with the current year presentation.

These statements should be read in conjunction with the financial statements and notes included in the combined Annual Report on Form 10-K for the year ended December 31, 2003 for FirstEnergy and the Companies. The preparation of financial statements in conformity with GAAP requires management to make periodic estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and disclosure of contingent assets and liabilities. Actual results could differ from those estimates. The reported results of operations are not indicative of results of operations for any future period.

FirstEnergy s and the Companies independent registered public accounting firm has performed reviews of, and issued reports on, these consolidated interim financial statements in accordance with standards established by the PCAOB. Pursuant to Rule 436(c) under the Securities Act of 1933, their reports of those reviews should not be considered a report within the meaning of Section 7 and 11 of that Act, and the independent registered public accounting firm s liability under Section 11 does not extend to them.

2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

Consolidation

FirstEnergy and its subsidiaries consolidate all majority-owned subsidiaries over which they exercise control and, when applicable, entities for which they have a controlling financial interest, and VIEs for which FirstEnergy or any of its subsidiaries is the primary beneficiary. Intercompany transactions and balances are eliminated in consolidation. Investments in nonconsolidated affiliates (20-50 percent owned companies, joint ventures and partnerships) over which FirstEnergy and its subsidiaries have the ability to exercise significant influence, but not control, are accounted for on the equity basis.

FIN 46R addresses the consolidation of VIEs, including SPEs, that are not controlled through voting interests or in which the equity investors do not bear the residual economic risks and rewards. The first step under FIN 46R is to determine whether an entity is within the scope of FIN 46R, which occurs if it is deemed to be a VIE. FirstEnergy and its subsidiaries consolidate VIEs where they have determined that they are the primary beneficiaries as defined by FIN 46R.

Included in FirstEnergy s consolidated financial statements are PNBV and Shippingport, two VIEs created in 1996 and 1997, respectively, to refinance debt originally issued in connection with sale and leaseback transactions. PNBV and Shippingport financial data are included in the consolidated financial statements of OE and CEI, respectively.

PNBV was established to purchase a portion of the lease obligation bonds issued in connection with OE s 1987 sale and leaseback of its interests in the Perry Plant and Beaver Valley Unit 2. OE used debt and available funds to purchase the notes issued by PNBV. Ownership of PNBV includes a three-percent equity interest by a nonaffiliated third party and a three-percent equity interest held by OES Ventures, a wholly owned subsidiary of OE. As required by FIN 46R, consolidation of PNBV by FirstEnergy and OE as of December 31, 2003 changed the previously reported trust investment of $361 million to an investment in collateralized lease bonds of $372 million. The $11 million increase represented the minority interest in the total assets of PNBV.

Shippingport was established to purchase all of the lease obligation bonds issued in connection with CEI s and TE s Bruce Mansfield Plant sale and leaseback transaction in 1987. CEI and TE used debt and available funds to purchase the notes issued by Shippingport. Consolidation of this entity by CEI impacted the financial statements of CEI and TE but had no impact on the consolidated financial statements of FirstEnergy. Prior to the adoption of FIN 46R, the assets and liabilities of Shippingport were included on a proportionate basis in the financial statements of CEI and TE. Adoption of FIN 46R resulted in the consolidation of Shippingport by CEI as of December 31, 2003. Shippingport s note payable to TE of $199 million ($10 million current) and $208 million ($9 million current) as of September 30, 2004 and December 31, 2003, respectively, is included in long-term debt on CEI s Consolidated Balance Sheets.

Through its investment in PNBV, OE has, and through their investments in Shippingport, CEI and TE have, variable interests in certain owner trusts that acquired the interests in the Perry Plant and Beaver Valley Unit 2, in the case of OE, and the Bruce Mansfield Plant, in the case of CEI and TE. FirstEnergy concluded that OE, CEI and TE were not the primary beneficiaries of the relevant owner trusts and were therefore not required to consolidate these entities. The leases are accounted for as operating leases in accordance with GAAP. The combined purchase price of $3.1 billion for all of the interests acquired by the owner trusts in 1987 was funded with debt of $2.5 billion and equity of $600 million.

Each of OE, CEI and TE are exposed to losses under the applicable sale-leaseback agreements upon the occurrence of certain contingent events that each company considers unlikely to occur. OE, CEI and TE each have a maximum exposure to loss under these provisions of approximately $1 billion, which represents the net amount of casualty value payments upon the occurrence of specified casualty events that render the applicable plant worthless. Under the applicable sale and leaseback agreements, OE, CEI and TE have net minimum discounted lease payments of $696 million, $113 million and $572 million, respectively, that would not be payable if the casualty value payments are made. As of September 30, 2004, CEI and TE have recorded above-market lease obligations related to the Bruce Mansfield Plant and Beaver Valley Unit 2 totaling $1.0 billion (CEI $744 million and TE $299 million), of which $85 million (CEI $60 million and TE $25 million) is current.

CEI formed a wholly owned statutory business trust to sell preferred securities and invest the gross proceeds in 9% subordinated debentures of CEI. The sole assets of the trust are the subordinated debentures with an aggregate principal amount of $103 million. The trust s preferred securities are redeemable at 100% of their principal amount at CEI s option beginning in December 2006. CEI has effectively provided a full and unconditional guarantee of the trust s obligations under the preferred securities.

Met-Ed and Penelec each formed statutory business trusts for substantially similar transactions to those of CEI. However, ownership of the Met-Ed and Penelec trusts is through separate wholly owned limited partnerships. On June 1, 2004, Met-Ed extinguished the subordinated debentures held by its affiliated trust and redeemed all of the associated 7.35% preferred securities (aggregate value of $100 million). On September 1, 2004, Penelec extinguished the subordinated debentures held by its affiliated trust and redeemed all of the associated 7.34% preferred securities (aggregate value of $100 million).

Upon adoption of FIN 46R, the limited partnerships and statutory business trusts discussed above were no longer consolidated on the financial statements of FirstEnergy or, as applicable, CEI, Met-Ed or Penelec. As of December 31, 2003 and September 30, 2004, subordinated debentures held by the affiliated trusts were included in long-term debt of the applicable company and equity investments in the trusts were included in other investments.

FirstEnergy has evaluated its power purchase agreements and determined that certain NUG entities may be VIEs to the extent they own a plant that sells substantially all of its output to the Companies and the contract price for power is correlated with the plant s variable costs of production. FirstEnergy, through its subsidiaries JCP&L, Met-Ed and

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Penelec, maintains approximately 30 long-term power purchase agreements with NUG entities. The agreements were structured pursuant to the Public Utility Regulatory Policies Act of 1978. FirstEnergy was not involved in the creation of, and has no equity or debt invested in, these entities.

FirstEnergy has determined that for all but nine of these entities, neither JCP&L, Met-Ed or Penelec have variable interests in the entities or the entities are governmental or not-for-profit organizations not within the scope of FIN 46R. JCP&L, Met-Ed or Penelec may hold variable interests in the remaining nine entities, which sell their output at variable prices that correlate to some extent with the operating costs of the plants.

As required by FIN 46R, FirstEnergy has requested each quarter the information necessary from these nine entities to determine whether they are VIEs or whether JCP&L, Met-Ed or Penelec is the primary beneficiary. FirstEnergy has been unable to obtain the requested information, which in most cases, was deemed by the requested entity to be competitive and proprietary. As such, FirstEnergy applied the scope exception that exempts enterprises unable to obtain the necessary information to evaluate entities under FIN 46R. The maximum exposure to loss from these entities results from increases in the variable pricing component under the contract terms and cannot be determined without the requested data. The purchased power costs from these entities during the three months and nine months ended September 30, 2004 and 2003 were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2004	**2003**	**2004**	**2003**
		(In millions)		
JCP&L	$ 36	$ 31	$ 99	$ 89
Met-Ed	13	12	38	39
Penelec	7	7	20	20
Total	$ 56	$ 50	$ 157	$ 148

FirstEnergy is required to continue to make exhaustive efforts to obtain the necessary information in future periods and is unable to determine the possible impact of consolidating any such entity without this information.

Earnings Per Share

Basic earnings per share are computed using the weighted average of actual common shares outstanding during the respective period as the denominator. The denominator for diluted earnings per share reflects the weighted average of common shares outstanding plus the potential additional common shares that could result if dilutive securities and other agreements to issue common stock were exercised. Stock-based awards to purchase shares of common stock totaling 3.4 million in the nine months ended September 30, 2004 and 3.5 million in the three months and nine months ended September 30, 2003 were excluded from the calculation of diluted earnings per share of common stock because their exercise prices were greater than the average market price of common shares during the period. No stock-based awards were excluded from the calculation for the quarter ended September 30, 2004. The following table reconciles the denominators for basic and diluted earnings per share from Income Before Discontinued Operations and Cumulative Effect of Accounting Change:

Reconciliation of Basic and Diluted Earnings per Share	Three Months Ended September 30,		Nine Months Ended September 30,	
	2004	2003	2004	2003
	(In thousands)			
Income before discontinued operations and cumulative effect of accounting change	$298,622	$151,693	$676,666	$276,408
Average Shares of Common Stock Outstanding:				
Denominator for basic earnings per share (weighted average shares outstanding)	327,499	299,422	327,280	295,825
Assumed exercise of dilutive stock options and awards	1,600	1,329	1,570	1,328
Denominator for diluted earnings per share	329,099	300,751	328,850	297,153
Income Before Discontinued Operations and Cumulative Effect of Accounting Change, per common share:				
Basic	$ 0.91	$ 0.51	$ 2.07	$ 0.93
Diluted	$ 0.91	$ 0.50	$ 2.06	$ 0.93

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Preferred Stock Subject to Mandatory Redemption

Long-term debt includes the preferred stock of consolidated subsidiaries subject to mandatory redemption as of September 30, 2004 and December 31, 2003 in accordance with SFAS 150. Issued in May 2003 and effective July 1, 2003, SFAS 150 establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity; certain financial instruments that embody obligations for the issuer are required to be classified as liabilities. The adoption of SFAS 150 had no impact on FirstEnergy s Consolidated Statements of Income because dividends on applicable subsidiary preferred stock were previously included in net interest charges and required no reclassification. CEI and Penn, however, did not include the preferred dividends on their manditorily redeemable preferred stock in interest expense for the first six months of 2003, but have included the dividends in interest charges for the three months ended September 30, 2004 and 2003, and the nine months ended September 30, 2004.

Securitized Transition Bonds

The consolidated financial statements of FirstEnergy and JCP&L include the results of JCP&L Transition, a wholly owned limited liability company of JCP&L. In June 2002, JCP&L Transition sold $320 million of transition bonds to securitize the recovery of JCP&L s bondable stranded costs associated with the previously divested Oyster Creek Nuclear Generating Station.

JCP&L did not purchase and does not own any of the transition bonds, which are included as long-term debt on FirstEnergy s and JCP&L s Consolidated Balance Sheets. The transition bonds are obligations of JCP&L Transition only and are collateralized solely by the equity and assets of JCP&L Transition, which consist primarily of bondable transition property. The bondable transition property is solely the property of JCP&L Transition.

Bondable transition property represents the irrevocable right under New Jersey law of a utility company to charge, collect and receive from its customers, through a non-bypassable TBC, the principal amount and interest on the transition bonds and other fees and expenses associated with their issuance. JCP&L sold the bondable transition property to JCP&L Transition and, as servicer, manages and administers the bondable transition property, including the billing, collection and remittance of the TBC, pursuant to a servicing agreement with JCP&L Transition. JCP&L is entitled to a quarterly servicing fee of $100,000 that is payable from TBC collections.

Derivative Accounting

FirstEnergy is exposed to financial risks resulting from the fluctuation of interest rates and commodity prices, including electricity, natural gas and coal. To manage the volatility relating to these exposures, FirstEnergy uses a variety of non-derivative and derivative instruments, including forward contracts, options, futures contracts and swaps. The derivatives are used principally for hedging purposes, and to a lesser extent, for trading purposes. FirstEnergy s Risk Policy Committee, comprised of executive officers, exercises an independent risk oversight function to ensure compliance with corporate risk management policies and prudent risk management practices.

Derivatives are recognized as assets or liabilities at fair value unless they qualify for an exception under SFAS 133. All changes in the fair value of derivatives are recognized currently in earnings unless specific hedge criteria are met. Gains and losses from derivative contracts that do not qualify as hedges of commodity price or interest rate risk are included in other operating expenses.

SFAS 133 provides that the effective portion of the gain or loss on a derivative instrument designated and qualifying as a cash flow hedging instrument be reported as a component of other comprehensive income and be reclassified into earnings in the same period during which the hedged forecasted transaction affects earnings. The ineffective portion of hedge gains and losses is also included in net income. FirstEnergy s primary ongoing hedging activity involves cash flow hedges of electricity and natural gas purchases. The maximum periods over which the variability of electricity and natural gas cash flows are hedged are two and three years, respectively. In 2001, FirstEnergy entered into interest rate derivative transactions to hedge a portion of the anticipated interest payments on debt related to the GPU acquisition. Gains and losses from these cash flow hedges were reported in other comprehensive income and are included in net income over the periods that the hedged interest payments are made 5, 10 and 30 years.

The net deferred loss of $93 million included in AOCL as of September 30, 2004, for derivative hedging activity, as compared to the June 30, 2004 balance of $100 million in net deferred losses, resulted from a $5 million reduction related to current hedging activity and a $2 million decrease due to net hedge losses included in earnings during the three months ended September 30, 2004. Approximately $12 million (after tax) of the net deferred loss on derivative instruments in AOCL as of September 30, 2004, is expected to be reclassified to earnings during the next twelve months as hedged transactions occur. The fair value of these derivative instruments will fluctuate from period to period based on various market factors.

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FirstEnergy has entered into fair value hedges of fixed-rate, long-term debt issues to protect against the risk of changes in the fair value of fixed-rate debt instruments due to lower interest rates. Swap maturities, call options, fixed interest rates received, and interest payment dates match those of the underlying debt obligations. As of September 30, 2004, FirstEnergy maintained fixed-for-floating interest rate swap agreements with an aggregate notional amount of $1.7 billion. Under these agreements, FirstEnergy receives fixed cash flows based on the fixed coupons of hedged securities and pays variable cash flows based on short-term variable market interest rates. The weighted average fixed interest rate of senior notes and subordinated debentures hedged by the swap agreements was 5.53%. The interest rate swaps have effectively converted that rate to a current, weighted average variable interest rate of 3.02%. Changes in the fair value of derivatives designated as fair value hedges and the corresponding changes in the fair value of the hedged risk attributable to a recognized asset, liability, or unrecognized firm commitment are recorded in earnings. If the fair value hedge is effective, the amounts recorded will offset in earnings. FirstEnergy did not enter into any new fixed-for-floating interest rate swap agreements during the third quarter of 2004.

Goodwill

In a business combination, the excess of the purchase price over the estimated fair values of assets acquired and liabilities assumed is recognized as goodwill. Based on the guidance provided by SFAS 142, FirstEnergy evaluates its goodwill for impairment at least annually and would make such an evaluation more frequently if indicators of impairment should arise. In accordance with the accounting standard, if the fair value of a reporting unit is less than its carrying value (including goodwill), the goodwill is tested for impairment. If an impairment is indicated, FirstEnergy recognizes a loss calculated as the difference between the implied fair value of a reporting unit s goodwill and the carrying value of the goodwill. FirstEnergy s 2003 annual review resulted in a non-cash goodwill impairment charge of $122 million in the third quarter of 2003, reducing the carrying value of FSG. Of this amount, $117 million was reported as an operating expense and $5 million was included in the results from discontinued operations. The impairment charge reflected the slow down in the development of competitive retail markets and depressed economic conditions that affected the value of FSG. The fair value of FSG was estimated using primarily the expected discounted future cash flows. FirstEnergy s 2004 annual review was completed in the third quarter of 2004 with no impairment indicated.

As of September 30, 2004, FirstEnergy had $6.1 billion of goodwill that primarily relates to its regulated services segment. In the first nine months of 2004, FirstEnergy adjusted goodwill related to the former GPU companies for interest received on a pre-merger income tax refund and for the reversal of tax valuation allowances related to income tax benefits realized attributable to prior period capital loss carryforwards that were offset by capital gains generated in 2004. A summary of the change in goodwill during the nine months ended September 30, 2004 is shown below:

	FirstEnergy	CEI	TE	JCP&L	Met-Ed	Penelec
			(In millions)			
Goodwill Reconciliation						
Balance as of December 31, 2003	$6,128	$1,694	$505	$2,001	$ 884	$ 899
Adjustments related to GPU acquisition	(27)			(5)	(7)	(15)
Balance as of September 30, 2004	$6,101	$1,694	$505	$1,996	$ 877	$ 884

Asset Retirement Obligations

FirstEnergy recognizes a liability for retirement obligations associated with tangible assets in accordance with SFAS 143. FirstEnergy has identified applicable legal obligations as defined under the standard for nuclear power plant decommissioning, reclamation of a sludge disposal pond related to the Bruce Mansfield Plant and closure of two coal ash disposal sites. The ARO liability was $1.060 billion as of September 30, 2004 and included $1.046 billion for nuclear decommissioning of the Beaver Valley, Davis-Besse, Perry and TMI-2 nuclear generating facilities. The Companies share of the obligation to decommission these units was developed based on site specific studies performed by an independent engineer. FirstEnergy utilized an expected cash flow approach (as discussed in FCON 7) to measure the fair value of the nuclear decommissioning ARO.

In the third quarter of 2004, FirstEnergy revised the ARO associated with TMI-2 as the result of a recently completed study and the anticipated operating license extension at TMI-1. The abandoned TMI-2 is adjacent to TMI-1 and the units will be decommissioned on a concurrent timeline. The license holder at TMI-1 has indicated plans to file for a 20-year extension of its operating license, which currently expires in 2014. The decrease in the present value of estimated cash flows associated with the license extension of $202 million, was partially offset by the $26 million present value of an increase in projected decommissioning costs. The net decrease in the TMI-2 ARO liability and corresponding regulatory asset was $176 million (JCP&L $43 million, Met-Ed - $89 million and Penelec $44 million).

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The Companies maintain nuclear decommissioning trust funds that are legally restricted for purposes of settling the nuclear decommissioning ARO. As of September 30, 2004, the fair value of the decommissioning trust assets was $1.462 billion.

The following tables provide the beginning and ending aggregate carrying amount of the ARO and the changes to the balance during the three months and nine months ended September 30, 2004 and 2003, respectively.

Three Months	FirstEnergy	OE	CEI	TE	Penn	JCP&L	Met-Ed	Penelec
	(In millions)							
ARO Reconciliation								
Balance, July 1, 2004	$1,217	$194	$263	$188	$134	$ 113	$ 216	$ 108
Liabilities incurred								
Liabilities settled								
Accretion	19	4	5	3	2	2	3	1
Revisions in estimated cash flows	(176)					(43)	(89)	(44)
Balance, September 30, 2004	$1,060	$198	$268	$191	$136	$ 72	$ 130	$ 65
Balance, July 1, 2003	$1,145	$182	$246	$178	$126	$ 107	$ 204	$ 102
Liabilities incurred								
Liabilities settled								
Accretion	16	3	5	1	1	1	3	2
Revisions in estimated cash flows								
Balance, September 30, 2003	$1,161	$185	$251	$179	$127	$ 108	$ 207	$ 104

Nine Months	FirstEnergy	OE	CEI	TE	Penn	JCP&L	Met-Ed	Penelec
	(In millions)							
ARO Reconciliation								
Balance, January 1, 2004	$1,179	$188	$255	$182	$130	$ 110	$ 210	$ 105
Liabilities incurred								
Liabilities settled								
Accretion	57	10	13	9	6	5	9	4
Revisions in estimated cash flows	(176)					(43)	(89)	(44)
Balance, September 30, 2004	$1,060	$198	$268	$191	$136	$ 72	$ 130	$ 65
Balance, January 1, 2003	$1,109	$176	$238	$172	$122	$ 104	$ 198	$ 99

Liabilities incurred								
Liabilities settled								
Accretion	52	9	13	7	5	4	9	5
Revisions in estimated cash flows								
Balance, September 30, 2003	$1,161	$185	$251	$179	$127	$ 108	$ 207	$ 104

Stock-Based Compensation

FirstEnergy applies the recognition and measurement principles of APB 25 and related Interpretations in accounting for its stock-based compensation plans. No material stock-based employee compensation expense is reflected in net income as all options granted under those plans have exercise prices equal to the market value of the underlying common stock on the respective grant dates, resulting in substantially no intrinsic value.

In March 2004, the FASB issued an exposure draft of a proposed standard that, if adopted, will change the accounting for employee stock options and other equity-based compensation. The proposed standard would require companies to expense the fair value of stock options determined on the grant date. In October 2004, the FASB amended the proposed standard to delay its effective date from January 1, 2005 to interim and annual periods beginning after June 15, 2005 (see Note 7). FirstEnergy will not be able to determine the impact of the proposed standard until it is issued in final form. The table below summarizes the effects on the Company s net income and earnings per share had the Company applied the fair value recognition provisions of SFAS 123 to stock-based employee compensation in the current reporting periods.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2004	2003	2004	2003
	(In thousands)		(In thousands)	
Net income, as reported	$298,622	$152,719	$676,666	$313,333
Add back compensation expense reported in net income, net of tax (based on APB 25)		40		131
Deduct compensation expense based upon estimated fair value, net of tax	(3,432)	(3,138)	(11,025)	(9,314)
Adjusted net income	$295,190	$149,621	$665,641	$304,150
Earnings Per Share of Common Stock				
Basic				
As Reported	$ 0.91	$ 0.51	$ 2.07	$ 1.06
Adjusted	$ 0.90	$ 0.50	$ 2.03	$ 1.03
Diluted				
As Reported	$ 0.91	$ 0.50	$ 2.06	$ 1.05
Adjusted	$ 0.90	$ 0.50	$ 2.02	$ 1.02

Discontinued Operations

FirstEnergy s discontinued operations consisted of net income of $1 million in the third quarter of 2003 and net losses of $65 million in the first nine months of 2003 from its Argentina and Bolivia businesses and certain domestic operations divested in 2003. The related revenues, expenses and taxes were reclassified from the previously reported Consolidated Statement of Income for the nine months ended September 30, 2003 and reported as a net amount in Discontinued Operations. In April 2003, FirstEnergy divested its ownership in Emdersa through the abandonment of its shares in Emdersa s parent company, GPU Argentina Holdings, Inc. The abandonment was accomplished by relinquishing FirstEnergy s shares to the independent Board of Directors of GPU Argentina Holdings, relieving FirstEnergy of all rights and obligations relative to this business. As a result of the abandonment, FirstEnergy recognized a one-time, non-cash charge of $67 million (no income tax benefit was recognized), or $0.23 per share of common stock, in the second quarter of 2003. This charge resulted from realizing CTA losses through earnings ($90 million, or $0.30 per share of common stock), partially offset by the gain recognized from abandoning FirstEnergy s investment in Emdersa ($23 million, or $0.07 per share of common stock). Since FirstEnergy had previously recorded $90 million of CTA adjustments in OCI, the net effect of the $67 million charge was an increase in common stockholders equity of $23 million. FirstEnergy sold its Bolivia operations, Empresa Guaracachi S.A., in December 2003. Domestic operations sold in 2003 consisted of three former FSG subsidiaries and the MARBEL subsidiary, NEO.

Cumulative Effect of Accounting Change

As a result of adopting SFAS 143 in January 2003, FirstEnergy recorded a $175 million increase to income, $102 million net of tax, or basic earnings of $0.35 per share ($0.34 diluted) of common stock in the nine months ended September 30, 2003. Upon adoption of the accounting standard, FirstEnergy reversed accrued nuclear plant decommissioning costs of $1.23 billion and recorded an ARO of $1.11 billion, including accumulated accretion of

$507 million for the period from the date the liability was incurred to the date of adoption. FirstEnergy also recorded asset retirement costs of $602 million as part of the carrying amount of the related long-lived asset and accumulated depreciation of $415 million. FirstEnergy recognized a regulatory liability of $185 million for the transition amounts expected to be recovered through rates related to the ARO for nuclear decommissioning. The cumulative effect adjustment also included the reversal of $60 million in accumulated estimated removal costs for non-regulated generation assets.

The impact of adopting SFAS 143 on the financial statements of each of the Companies effective January 1, 2003, is shown in the table below:

	OE	CEI	TE	Penn	JCP&L	Met-Ed	Penelec
				(In millions)			
Asset retirement costs	$134	$ 50	$ 41	$ 78	$ 98	$ 186	$ 93
Accumulated depreciation	25	7	6	9	98	186	93
Asset retirement obligation	298	238	172	121	104	198	99
Cumulative effect adjustment, pretax	54	73	44	18		0.4	2
Cumulative effect adjustment, net of tax	32	42	26	11		0.2	1

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Restatements of TE, JCP&L and Penelec Previously Reported Quarterly Results

Earnings for the three months and nine months ended September 30, 2003 have been restated for TE, JCP&L and Penelec to reflect adjustments to costs that were subsequently capitalized to construction projects. The results for TE have also been restated to correct the amount reported for interest expense. TE s costs, which were originally recorded as operating expenses and subsequently capitalized to construction, were $1.1 million ($0.7 million after-tax) and $2.1 million ($1.2 million after-tax) in the third quarter and the first nine months of 2003, respectively. TE s interest expense was overstated by $0.3 million ($0.2 million after-tax) and $1.6 million ($1.0 million after-tax) in the third quarter and the first nine months of 2003, respectively. Similar to TE, JCP&L s capital costs originally recorded as operating expenses were $5.8 million ($3.4 million after-tax) and $9.0 million ($5.3 million after-tax) in the third quarter and the first nine months of 2003, respectively. Penelec s capital costs originally recorded as operating expenses were $2.0 million ($1.2 million after-tax) and $2.7 million ($1.6 million after-tax) in the third quarter and the first nine months of 2003, respectively. In addition, certain revenues and expenses have been reclassified and presented on a net basis to conform with the current year presentation (see Note 1). The impacts of these adjustments were not material to the consolidated balance sheets or consolidated statements of cash flows for TE, JCP&L or Penelec for any quarter of 2003.

The effects of these adjustments on the consolidated statements of income previously reported for TE, JCP&L and Penelec for the three months and nine months ended September 30, 2003 are as follows:

TE

	Three Months Ended September 30, 2003		Nine Months Ended September 30, 2003	
	As Previously Reported	**As Restated**	**As Previously Reported**	**As Restated**
	(In thousands)			
Operating revenues	$260,190	$260,197	$708,000	$708,007
Operating expenses	241,987	241,447	686,400	685,813
Operating income	18,203	18,750	21,600	22,194
Other income	5,768	5,724	12,644	12,600
Net interest charges	8,220	7,872	29,605	27,982
Income before cumulative effect of accounting change	15,751	16,602	4,639	6,812
Cumulative effect of accounting change			25,550	25,550
Net income	15,751	16,602	30,189	32,362
Preferred stock dividend requirements	2,211	2,211	6,627	6,627
Earnings attributable to common stock	$ 13,540	$ 14,391	$ 23,562	$ 25,735

JCP&L

	Three Months Ended September 30, 2003		Nine Months Ended September 30, 2003	
	As Previously Reported	As Restated	As Previously Reported	As Restated
	(In thousands)			
Operating revenues	$743,145	$741,293	$1,942,868	$1,941,016
Operating expenses	659,526	653,761	1,807,539	1,799,876
Operating income	83,619	87,532	135,329	141,140
Other income	1,061	557	4,501	3,997
Net interest charges	20,517	20,517	65,429	65,429
Net income	64,163	67,572	74,401	79,708
Preferred stock dividend requirements	125	125	(238)	(238)
Earnings attributable to common stock	$ 64,038	$ 67,447	$ 74,639	$ 79,946

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Penelec

	Three Months Ended September 30, 2003		Nine Months Ended September 30, 2003	
	As Previously Reported	As Restated	As Previously Reported	As Restated
	(In thousands)			
Operating revenues	$242,960	$242,146	$729,762	$728,948
Operating expenses	230,484	228,476	688,725	686,311
Operating income	12,476	13,670	41,037	42,637
Other income	545	522	887	864
Net interest charges	9,046	9,046	25,451	25,451
Income before cumulative effect of accounting change	3,975	5,146	16,473	18,050
Cumulative effect of accounting change			1,096	1,096
Net income	$ 3,975	$ 5,146	$ 17,569	$ 19,146

3 COMMITMENTS, GUARANTEES AND CONTINGENCIES:

Capital Expenditures

FirstEnergy s current forecast reflects expenditures of approximately $2.3 billion (OE $295 million, CEI $275 million, TE $141 million, Penn $143 million, JCP&L $446 million, Met-Ed $168 million, Penelec $198 million, ATSI $66 million, FES $443 million and other subsidiaries $125 million) for property additions and improvements from 2004-2006, of which approximately $717 million (OE $113 million, CEI $92 million, TE $48 million, Penn $65 million, JCP&L $142 million, Met-Ed $53 million, Penelec $60 million, ATSI $24 million, FES $87 million and other subsidiaries-$33 million) is applicable to 2004. Investments for additional nuclear fuel during the 2004-2006 period are estimated to be approximately $303 million (OE $84 million, CEI $100 million, TE $64 million and Penn $55 million), of which approximately $90 million (OE $26 million, CEI $30 million, TE $16 million and Penn $18 million) applies to 2004.

Guarantees and Other Assurances

As part of normal business activities, FirstEnergy and the Companies enter into various agreements to provide financial or performance assurances to third parties. As of September 30, 2004, outstanding guarantees and other assurances aggregated $2.1 billion and included contract guarantees ($1.0 billion), surety bonds ($0.3 billion) and letters of credit ($0.8 billion).

FirstEnergy guarantees energy and energy-related payments of its subsidiaries involved in energy marketing activities principally to facilitate normal physical transactions involving electricity, gas, emission allowances and coal. FirstEnergy also provides guarantees to various providers of subsidiary financing principally for the acquisition of property, plant and equipment. These agreements legally obligate FirstEnergy and its subsidiaries to fulfill the obligations of those subsidiaries directly involved in energy and energy-related transactions or financing where the law might otherwise limit the counterparties claims. If demands of a counterparty were to exceed the ability of a subsidiary to satisfy existing obligations, FirstEnergy s guarantee enables the counterparty s legal claim to be satisfied by other FirstEnergy assets. The likelihood is remote that such parental guarantees of $0.9 billion (included in the $1.0 billion discussed above) as of September 30, 2004 will increase amounts otherwise to be paid by FirstEnergy to meet its obligations incurred in connection with financings and ongoing energy and energy-related activities.

While guarantees are normally parental commitments for the future payment of subsidiary obligations, subsequent to the occurrence of a credit rating downgrade or material adverse event the immediate payment of cash collateral or provision of an LOC may be required. The following table summarizes collateral provisions as of September 30, 2004:

		Collateral Paid		
Collateral Provisions	**Total Exposure(1)**	**Cash**	**Letters of Credit**	**Remaining Exposure**
		(In millions)		
Rating downgrade	$ 358	$ 145	$ 18	$ 195
Adverse event	113		23	90
Total	$ 471	$ 145	$ 41	$ 285

(1) As of October 12, 2004, FirstEnergy s total exposure decreased to $465 million and the remaining exposure decreased to $272 million net of $152 million of cash collateral and $41 million of LOC provided to counterparties.

Most of FirstEnergy s surety bonds are backed by various indemnities common within the insurance industry. Surety bonds and related FirstEnergy guarantees of $280 million provide additional assurance to outside parties that contractual and statutory obligations will be met in a number of areas including construction jobs, environmental commitments and various retail transactions.

In connection with the sale of the TEBSA project in Colombia in January 2004, FirstEnergy guaranteed the obligations of the operators of the project, up to a maximum of $6 million (subject to escalation) under the project s operation and maintenance agreement for so long as such obligations exist. The purchaser of TEBSA agreed to indemnify FirstEnergy against any loss under this guarantee. Also in connection with the TEBSA project, FirstEnergy has provided the TEBSA project lenders with a $60 million LOC and a $400,000 LOC. The $60 million LOC was established as a substitute asset for FirstEnergy s interest in its Midlands companies pursuant to an indemnity agreement in favor of the TEBSA project lenders. As of October 15, 2004, the value of the LOC decreased to $46 million. The balance will continue to decline annually and will be fully discharged and released in October 2010. The substitute LOC enabled FirstEnergy to sell its remaining 20.1% interest in Avon (parent of Midlands Electricity in the United Kingdom). The $400,000 LOC was established to secure the TEBSA project lenders in the event that liquidated shares of TEBSA were unable to be converted into U.S. currency. The $400,000 LOC will terminate upon the registration of certain of TEBSA s stock with the Colombian Central Bank.

Environmental Matters

Various federal, state and local authorities regulate the Companies with regard to air and water quality and other environmental matters. The effects of compliance on the Companies with regard to environmental matters could have a material adverse effect on FirstEnergy s earnings and competitive position. These environmental regulations affect FirstEnergy s earnings and competitive position to the extent that it competes with companies that are not subject to such regulations and therefore do not bear the risk of costs associated with compliance, or failure to comply, with such regulations. Overall, FirstEnergy believes it is in material compliance with existing regulations but is unable to predict future change in regulatory policies and what, if any, the effects of such change would be. FirstEnergy estimates additional capital expenditures for environmental compliance of approximately $91 million for 2004 through 2006, which is included in the $2.3 billion of forecasted capital expenditures for 2004 through 2006.

Clean Air Act Compliance

The Companies are required to meet federally approved SO_2 regulations. Violations of such regulations can result in shutdown of the generating unit involved and/or civil or criminal penalties of up to $31,500 for each day the unit is in violation. The EPA has an interim enforcement policy for SO_2 regulations in Ohio that allows for compliance based on a 30-day averaging period. The Companies cannot predict what action the EPA may take in the future with respect to the interim enforcement policy.

The Companies believe they are complying with SO_2 reduction requirements under the Clean Air Act Amendments of 1990 by burning lower-sulfur fuel, generating more electricity from lower-emitting plants, and/or using emission allowances. NO_x reductions required by the 1990 Amendments are being achieved through combustion controls and the generation of more electricity at lower-emitting plants. In September 1998, the EPA finalized regulations requiring additional NO_x reductions from the Companies facilities. The EPA s NO_x Transport Rule imposes uniform reductions of NO_x emissions (an approximate 85% reduction in utility plant NO_x emissions from projected 2007 emissions) across a region of nineteen states (including Michigan, New Jersey, Ohio and Pennsylvania) and the District of Columbia based on a conclusion that such NO_x emissions are contributing significantly to ozone levels in the eastern United States. SIPs were required to comply by May 31, 2004 with individual state NO_x budgets. New Jersey and Pennsylvania submitted a SIP that required compliance with the state NO_x budgets at the Companies New Jersey and Pennsylvania facilities by May 1, 2003. Michigan and Ohio submitted a SIP that required compliance with the state NO_x budgets at the Companies Michigan and Ohio facilities by May 31,

2004. The Companies believe their facilities are complying with the state NO_x budgets through combustion controls and post-combustion controls, including Selective Catalytic Reduction and Selective Non-Catalytic Reduction systems, and/or using emission allowances.

National Ambient Air Quality Standards

In July 1997, the EPA promulgated changes in the NAAQS for ozone and proposed a new NAAQS for fine particulate matter. On December 17, 2003, the EPA proposed the Interstate Air Quality Rule covering a total of 29 states (including New Jersey, Ohio and Pennsylvania) and the District of Columbia based on proposed findings that air pollution emissions from 29 eastern states and the District of Columbia significantly contribute to nonattainment of the NAAQS for fine particles and/or the 8-hour ozone NAAQS in other states. The EPA has proposed the Interstate Air Quality Rule to cap-and-trade NO_x and SO_2 emissions in two phases (Phase I in 2010 and Phase II in 2015). According to the EPA, SO_2 emissions would be reduced by approximately 3.6 million tons in 2010, across states covered by the rule, with reductions ultimately reaching more than 5.5 million tons annually. NO_x emission reductions would measure about 1.5 million tons in 2010 and 1.8 million tons in 2015. The future cost of compliance with these proposed regulations may be substantial and will depend on whether and how they are ultimately implemented by the states in which the Companies operate affected facilities.

Mercury Emissions

In December 2000, the EPA announced it would proceed with the development of regulations regarding hazardous air pollutants from electric power plants, identifying mercury as the hazardous air pollutant of greatest concern. On December 15, 2003, the EPA proposed two different approaches to reduce mercury emissions from coal-fired power plants. The first approach would require plants to install controls known as MACT based on the type of coal burned. According to the EPA, if implemented, the MACT proposal would reduce nationwide mercury emissions from coal-fired power plants by 14 tons to approximately 34 tons per year. The second approach proposes a cap-and-trade program that would reduce mercury emissions in two distinct phases. Initially, mercury emissions would be reduced by 2010 as a co-benefit from implementation of SO_2 and NO_x emission caps under the EPA s proposed Interstate Air Quality Rule. Phase II of the mercury cap-and-trade program would be implemented in 2018 to cap nationwide mercury emissions from coal-fired power plants at 15 tons per year. The EPA has agreed to choose between these two options and issue a final rule by March 15, 2005. The future cost of compliance with these regulations may be substantial.

W. H. Sammis Plant

In 1999 and 2000, the EPA issued NOV or Compliance Orders to nine utilities covering 44 power plants, including the W. H. Sammis Plant, which is owned by OE and Penn. In addition, the U.S. Department of Justice filed eight civil complaints against various investor-owned utilities, which included a complaint against OE and Penn in the U.S. District Court for the Southern District of Ohio. These cases are referred to as New Source Review cases. The NOV and complaint allege violations of the Clean Air Act based on operation and maintenance of the W. H. Sammis Plant dating back to 1984. The complaint requests permanent injunctive relief to require the installation of best available control technology and civil penalties of up to $27,500 per day of violation. On August 7, 2003, the United States District Court for the Southern District of Ohio ruled that 11 projects undertaken at the W. H. Sammis Plant between 1984 and 1998 required pre-construction permits under the Clean Air Act. The ruling concludes the liability phase of the case, which deals with applicability of Prevention of Significant Deterioration provisions of the Clean Air Act. The remedy phase trial to address civil penalties and what, if any, actions should be taken to further reduce emissions at the plant has been rescheduled to January 2005 by the Court because the parties are engaged in meaningful settlement negotiations. The Court indicated, in its August 2003 ruling, that the remedies it may consider and impose involved a much broader, equitable analysis, requiring the Court to consider air quality, public health, economic impact, and employment consequences. The Court may also consider the less than consistent efforts of the EPA to apply and further enforce the Clean Air Act. The potential penalties that may be imposed, as well as the capital expenditures necessary to comply with substantive remedial measures that may be required, could have a material adverse impact on FirstEnergy s, OE s and Penn s respective financial condition and results of operations. While the parties are engaged in meaningful settlement discussions, management is unable to predict the ultimate outcome of this matter and no liability has been accrued as of September 30, 2004.

Regulation of Hazardous Waste

As a result of the Resource Conservation and Recovery Act of 1976, as amended, and the Toxic Substances Control Act of 1976, federal and state hazardous waste regulations have been promulgated. Certain fossil-fuel combustion waste products, such as coal ash, were exempted from hazardous waste disposal requirements pending the EPA s evaluation of the need for future regulation. The EPA subsequently determined that regulation of coal ash as a hazardous waste is unnecessary. In April 2000, the EPA announced that it will develop national standards regulating disposal of coal ash under its authority to regulate nonhazardous waste.

The Companies have been named as PRPs at waste disposal sites which may require cleanup under the Comprehensive Environmental Response, Compensation and Liability Act of 1980. Allegations of disposal of hazardous substances at historical sites and the liability involved are often unsubstantiated and subject to dispute; however, federal law provides that all PRPs for a particular site are liable on a joint and several basis. Therefore, environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheet as of September 30, 2004, based on estimates of the total costs of cleanup, the Companies proportionate responsibility for such costs and the financial ability of other nonaffiliated entities to pay. In addition, JCP&L has accrued liabilities for environmental remediation of former manufactured gas plants in New Jersey; those costs are being recovered by JCP&L through a non-bypassable SBC. Included in Current Liabilities and Other Noncurrent Liabilities are accrued liabilities aggregating approximately $65 million (JCP&L $45.8 million, CEI $2.4 million, TE $0.2 million, Met-Ed $28,000, Penelec $26,000, and other $16.3 million) as of September 30, 2004. The Companies accrue environmental liabilities only when they can conclude that it is probable that they have an obligation for such costs and can reasonably determine the amount of such costs. Unasserted claims are reflected in the Companies determination of environmental liabilities and are accrued in the period that they are both probable and reasonably estimable.

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Climate Change

In December 1997, delegates to the United Nations climate summit in Japan adopted an agreement, the Kyoto Protocol (Protocol), to address global warming by reducing the amount of man-made greenhouse gases emitted by developed countries by 5.2% from 1990 levels between 2008 and 2012. The United States signed the Protocol in 1998 but it failed to receive the two-thirds vote of the U.S. Senate required for ratification. However, the Bush administration has committed the United States to a voluntary climate change strategy to reduce domestic greenhouse gas intensity the ratio of emissions to economic output by 18% through 2012.

The Companies cannot currently estimate the financial impact of climate change policies, although the potential restrictions on CO_2 emissions could require significant capital and other expenditures. However, the CO_2 emissions per kilowatt-hour of electricity generated by the Companies is lower than many regional competitors due to the Companies diversified generation sources which includes low or non-CO_2 emitting gas-fired and nuclear generators.

Clean Water Act

Various water quality regulations, the majority of which are the result of the federal Clean Water Act and its amendments, apply to the Companies plants. In addition, Ohio, New Jersey and Pennsylvania have water quality standards applicable to the Companies operations. As provided in the Clean Water Act, authority to grant federal National Pollutant Discharge Elimination System water discharge permits can be assumed by a state. Ohio, New Jersey and Pennsylvania have assumed such authority.

On September 7, 2004, the EPA established new performance standards under Clean Water Act Section 316(b) for reducing impacts on fish and shellfish from cooling water intake structures at certain existing large electric generating plants. The regulations call for reductions in impingement mortality, when aquatic organisms are pinned against screens or other parts of a cooling water intake system and entrainment, which occurs when aquatic species are drawn into a facility s cooling water system. The Companies are conducting comprehensive demonstration studies, due in 2008, to determine the operational measures, equipment or restoration activities, if any, necessary for compliance by their facilities with the performance standards. FirstEnergy is unable to predict the outcome of such studies. Depending on the outcome of such studies, the future cost of compliance with these standards may be substantial.

Power Outages and Related Litigation

In July 1999, the Mid-Atlantic states experienced a severe heat wave which resulted in power outages throughout the service territories of many electric utilities, including JCP&L s territory. In an investigation into the causes of the outages and the reliability of the transmission and distribution systems of all four New Jersey electric utilities, the NJBPU concluded that there was not a prima facie case demonstrating that, overall, JCP&L provided unsafe, inadequate or improper service to its customers. Two class action lawsuits (subsequently consolidated into a single proceeding) were filed in New Jersey Superior Court in July 1999 against JCP&L, GPU and other GPU companies, seeking compensatory and punitive damages arising from the July 1999 service interruptions in the JCP&L territory.

In August 2002, the trial court granted partial summary judgment to JCP&L and dismissed the plaintiffs claims for consumer fraud, common law fraud, negligent misrepresentation, and strict products liability. In November 2003, the trial court granted JCP&L s motion to decertify the class and denied plaintiffs motion to permit into evidence their class-wide damage model indicating damages in excess of $50 million. These class decertification and damage rulings were appealed to the Appellate Division. The Appellate Court issued a decision on July 8, 2004, affirming the decertification of the originally certified class but remanding for certification of a class limited to those customers directly impacted by the outages of transformers in Red Bank, New Jersey. On September 8, 2004, the New Jersey

Supreme Court denied the motions filed by plaintiffs and JCP&L for leave to appeal the decision of the Appellate Court. FirstEnergy is unable to predict the outcome of these matters and no liability has been accrued as of September 30, 2004.

On August 14, 2003, various states and parts of southern Canada experienced widespread power outages. The outages affected approximately 1.4 million customers in FirstEnergy s service area. On April 5, 2004, the U.S. Canada Power System Outage Task Force released its final report on the outages. In the final report, the Task Force concluded, among other things, that the problems leading to the outages began in FirstEnergy s Ohio service area. Specifically, the final report concludes, among other things, that the initiation of the August 14, 2003 power outages resulted from an alleged failure of both FirstEnergy and ECAR to assess and understand perceived inadequacies within the FirstEnergy system; inadequate situational awareness of the developing conditions; and a perceived failure to adequately manage tree growth in certain transmission rights of way. The Task Force also concluded that there was a failure of the interconnected grid s reliability organizations (MISO and PJM) to provide effective diagnostic support. The final report is publicly available through the Department of Energy s website (www.doe.gov). FirstEnergy believes that the final report does not provide a complete and comprehensive picture of the conditions that contributed to the August 14, 2003 power outages and that it does not adequately address the underlying causes of the outages. FirstEnergy remains convinced that the outages cannot be explained by events on any one utility s system. The final report contains 46 recommendations to prevent or minimize the scope of future blackouts. Forty-five of those recommendations relate to broad industry or policy matters while one, including subparts, relates to activities the Task Force recommends be undertaken by FirstEnergy, MISO, PJM, and ECAR. FirstEnergy implemented several initiatives, both prior to and since the August 14, 2003 power outages, which are consistent with these and other recommendations and collectively enhance the reliability of its electric system. FirstEnergy certified to NERC on June 30, 2004, completion of various reliability recommendations and further received independent verification of completion status from a NERC verification team on July 14, 2004 (see Regulatory Matters below). FirstEnergy s implementation of these recommendations included completion of the Task Force recommendations that were directed toward FirstEnergy. As many of these initiatives already were in process and budgeted in 2004, FirstEnergy does not believe that any incremental expenses associated with additional initiatives undertaken during 2004 will have a material effect on its operations or financial results. FirstEnergy notes, however, that the applicable government agencies and reliability coordinators may take a different view as to recommended enhancements or may recommend additional enhancements in the future that could require additional, material expenditures. FirstEnergy has not accrued a liability as of September 30, 2004 for any expenditures in excess of those actually incurred through that date.

Three substantially similar actions were filed in various Ohio state courts by plaintiffs seeking to represent customers who allegedly suffered damages as a result of the August 14, 2003 power outages. All three cases were dismissed for lack of jurisdiction. One case was refiled at the PUCO and the other two have been appealed. In addition to the one case that was refiled at the PUCO, the Ohio Companies were named as respondents in a regulatory proceeding that was initiated at the PUCO in response to complaints alleging failure to provide reasonable and adequate service stemming primarily from the August 14, 2003 power outages.

One complaint has been filed against FirstEnergy in the New York State Supreme Court. In this case, several plaintiffs in the New York City metropolitan area allege that they suffered damages as a result of the August 14, 2003 power outages. None of the plaintiffs are customers of any FirstEnergy affiliate. FirstEnergy filed a motion to dismiss with the Court on October 22, 2004. No damage estimate has been provided and thus potential liability has not been determined.

FirstEnergy is vigorously defending these actions, but cannot predict the outcome of any of these proceedings or whether any further regulatory proceedings or legal actions may be instituted against the Companies. In particular, if FirstEnergy or its subsidiaries were ultimately determined to have legal liability in connection with these proceedings, it could have a material adverse effect on FirstEnergy s or its subsidiaries financial condition and results of operations.

Nuclear Plant Matters

FENOC received a subpoena in late 2003 from a grand jury sitting in the United States District Court for the Northern District of Ohio, Eastern Division requesting the production of certain documents and records relating to the inspection and maintenance of the reactor vessel head at the Davis-Besse plant. FirstEnergy is unable to predict the outcome of this investigation. In addition, FENOC remains subject to possible civil enforcement action by the NRC in connection with the events leading to the Davis-Besse outage in 2002. Further, a petition was filed with the NRC on March 29, 2004 by a group objecting to the NRC s restart order of the Davis-Besse Nuclear Power Station. The Petition seeks, among other things, suspension of the Davis-Besse operating license. A June 2, 2004 ASLB denial of the petition was appealed to the NRC. FENOC and the NRC staff filed opposition briefs on June 24, 2004. If it were ultimately determined that FirstEnergy or its subsidiaries has legal liability or is otherwise made subject to enforcement action based on the Davis-Besse outage, it could have a material adverse effect on FirstEnergy s or its subsidiaries financial condition and results of operations.

On August 12, 2004, the NRC publicly disclosed that it was notifying FirstEnergy that it will increase its regulatory oversight of the Perry Nuclear Power Plant as a result of problems with safety system equipment over the past two years. OE, CEI, TE and Penn own and/or lease the Perry Nuclear Power Plant. The NRC noted that the plant continues to operate safely. The increased oversight will include an extensive NRC team inspection to access the equipment problems and FirstEnergy s corrective actions. The outcome of this increased oversight is not known at this time.

Other Legal Matters

Various lawsuits, claims (including claims for asbestos exposure) and proceedings related to FirstEnergy s normal business operations are pending against FirstEnergy and its subsidiaries. The most significant not otherwise discussed above are described below.

On October 20, 2004, FirstEnergy was notified by the SEC that the previously disclosed informal inquiry initiated by the SEC s Division of Enforcement in September 2003 relating to the restatements in August 2003 of previously reported results by FirstEnergy and the Ohio Companies and the Davis-Besse extended outage has become the subject of a formal order of investigation. The SEC s formal order of investigation also encompasses issues raised during the SEC s examination of FirstEnergy and the Companies under the PUHCA. Concurrent with this notification, FirstEnergy received a subpoena asking for background documents and documents related to the restatements and Davis-Besse issues. FirstEnergy has cooperated fully with the informal inquiry and will continue to do so with the formal investigation.

Various legal proceedings alleging violations of federal securities laws and related state laws were filed against FirstEnergy in connection with, among other things, the restatements in August 2003 by FirstEnergy and the Ohio Companies of previously reported results, the August 14, 2003 power outages described above, and the extended outage at the Davis-Besse Nuclear Power Station. The lawsuits were filed against FirstEnergy and certain of its officers and directors. On July 27, 2004, FirstEnergy announced that it had reached an agreement to resolve these pending lawsuits. The settlement agreement, which does not constitute any admission of wrongdoing, provides for a total settlement payment of $89.9 million. Of that amount, FirstEnergy s insurance carriers will pay $71.92 million, based on a contractual pre-allocation, and FirstEnergy will pay $17.98 million, which resulted in an after-tax charge against FirstEnergy s second quarter and year-to-date 2004 earnings of $11 million or $0.03 per share of common stock (basic and diluted). The settlement has been preliminarily approved by the court with a final hearing scheduled for mid-December 2004. Although not anticipated to occur, in the event that a significant number of shareholders do not accept the terms of the settlement, FirstEnergy and individual defendants have the right, but not the obligation, to set aside the settlement and recommence the litigation.

On September 16, 2004, the FERC issued an order that imposed additional obligations on CEI under certain pre-Open Access transmission contracts among CEI and the cities of Cleveland and Painesville. Under the FERC s decision, CEI may be responsible for a portion of new energy market charges imposed by the MISO when its energy markets begin in the spring of 2005. CEI filed for rehearing of the order from the FERC on October 18, 2004. The impact of the FERC decision on CEI is dependent upon many factors, including the arrangements made by the cities for transmission service, the startup date for the MISO energy market, and the resolution of the rehearing request, and cannot be determined at this time.

If it were ultimately determined that FirstEnergy or its subsidiaries have legal liability or are otherwise made subject to liability based on any of the above matters, it could have a material adverse effect on FirstEnergy s or its subsidiaries financial condition and results of operations.

4 PENSION AND OTHER POSTRETIREMENT BENEFITS:

The components of FirstEnergy s net periodic pension cost, including amounts capitalized, consisted of the following:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Pension Benefits	**2004**	**2003**	**2004**	**2003**
	(In millions)			
Service cost	$ 19	$ 17	$ 58	$ 51
Interest cost	63	65	189	194
Expected return on plan assets	(71)	(64)	(215)	(191)
Amortization of prior service cost	2	2	7	7
Recognized net actuarial loss	10	16	29	48

Net periodic cost	$ 23	$ 36	$ 68	$ 109

In September 2004, FirstEnergy made a $500 million voluntary contribution to its pension plan. Prior to this contribution, projections indicated that cash contributions of approximately $600 million would have been required during the 2006 to 2007 time period under minimum funding requirements established by the IRS. The election to pre-fund the plan is expected to eliminate that funding requirement. Since the contribution is deductible for tax purposes, the after-tax cash impact of the voluntary contribution is approximately $300 million. The payment was funded by FirstEnergy s subsidiaries through existing short-term credit arrangements, including available intercompany money pools, as follows:

	(In millions)
OE	$ 60
CEI	32
TE	13
Penn	13
JCP&L	62
Met-Ed	39
Penelec	50
All other subsidiaries	231
Total	$500

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The components of FirstEnergy s net periodic other postretirement benefit cost, including amounts capitalized, consisted of the following:

Other Postretirement Benefits	Three Months Ended September 30, 2004	Three Months Ended September 30, 2003	Nine Months Ended September 30, 2004	Nine Months Ended September 30, 2003
	(In millions)			
Service cost	$ 9	$ 16	$ 27	$ 49
Interest cost	26	96	83	290
Expected return on plan assets	(10)	(95)	(32)	(285)
Amortization of prior service cost	(9)	4	(28)	11
Recognized net actuarial loss	9	24	29	72
Net periodic cost	$ 25	$ 45	$ 79	$ 137

FirstEnergy contributed $17 million to its other postretirement benefit plans in the nine months ended September 30, 2004. The Company has no funding requirements for the remainder of 2004.

Pension and postretirement benefit obligations are allocated to the subsidiaries employing the plan participants. The Companies capitalize employee benefits related to construction projects. The net periodic pension costs, including amounts capitalized, recognized by each of the Companies in the three and nine months ended September 30, 2004 and 2003 were as follows:

Pension Benefit Cost	Three Months Ended September 30, 2004	Three Months Ended September 30, 2003	Nine Months Ended September 30, 2004	Nine Months Ended September 30, 2003
	(In millions)			
OE	$ 1.7	$ 6.3	$ 5.2	$ 12.1
Penn	0.1	1.3	0.4	2.1
CEI	1.6	2.7	4.8	6.9
TE	0.8	1.4	2.3	3.5
JCP&L	1.9	3.2	5.6	14.2
Met-Ed	0.1	0.8	0.2	6.5
Penelec	0.1	1.1	0.4	7.7

The net periodic postretirement benefit costs, including amounts capitalized, recognized by each of the Companies in the three and nine months ended September 30, 2004 and 2003 were as follows:

Other Postretirement Benefit Cost	Three Months Ended September 30, 2004	Three Months Ended September 30, 2003	Nine Months Ended September 30, 2004	Nine Months Ended September 30, 2003
	(In millions)			
OE	$ 5.7	$ 11.4	$ 17.7	$ 20.3
Penn	1.2	2.2	3.7	3.5
CEI	4.4	3.4	13.7	9.8
TE	1.7	1.3	5.0	4.5
JCP&L	1.0	3.7	3.5	16.2
Met-Ed	0.7	2.2	2.5	8.7
Penelec	0.7	2.4	2.5	8.9

Pursuant to FSP 106-1 issued January 12, 2004, FirstEnergy began accounting for the effects of the Medicare Act effective January 1, 2004 because of a plan amendment during the quarter, which required remeasurement of the plan s obligations. The plan amendment, which increases cost-sharing by employees and retirees effective January 1, 2005, reduced postretirement benefit costs during the three months and nine months ended September 30, 2004, by $13 million and $35 million, respectively.

Consistent with the guidance in FSP 106-2 issued May 19, 2004, FirstEnergy recognized a reduction of $318 million in the accumulated postretirement benefit obligation as a result of the federal subsidy provided under the Medicare Act related to benefits for past service. The subsidy reduced net periodic postretirement benefit costs during the three months and nine months ended September 30, 2004, as follows:

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Impact of federal subsidy provided under the Medicare Act	**Three Months**	**Nine Months**
	(In millions)	
Service cost	$ (2)	$ (5)
Interest cost	(5)	(15)
Recognized net actuarial loss	(5)	(16)
Decrease in net periodic cost	$(12)	$ (36)

The impact of the subsidy was not material to the financial statements of each of the Companies for the three and nine months ended September 30, 2004.

5 - DIVESTITURES:

FirstEnergy completed the sale of its international operations during the quarter ended March 31, 2004 with the sales of its remaining 20.1% interest in Avon on January 16, 2004, and its 28.67% interest in TEBSA on January 30, 2004. Impairment charges related to Avon and TEBSA were recorded in the fourth quarter of 2003 and no gain or loss was recognized upon the sales in 2004. Avon, TEBSA and other international assets sold in 2003 were originally acquired as part of FirstEnergy s November 2001 merger with GPU.

FirstEnergy completed the sale of its 50% interest in GLEP on June 23, 2004. Proceeds of $220 million included cash of $200 million and the right, valued at $20 million, to participate for up to a 40% interest in future wells in Ohio. This transaction produced an after-tax loss of $7 million, or $0.02 per share of common stock, including the benefits of prior tax capital losses that had been previously fully reserved, which offset the capital gain from the sale.

6 - REGULATORY MATTERS:

In Ohio, New Jersey and Pennsylvania, laws applicable to electric industry deregulation contain similar provisions that are reflected in the Companies respective state regulatory plans. These provisions include:

allowing the Companies electric customers to select their generation suppliers;

establishing PLR obligations to non-shopping customers in the Companies service areas;

allowing recovery of potentially stranded investment (or transition costs) not otherwise recoverable in a competitive generation market;

itemizing (unbundling) the price of electricity into its component elements including generation, transmission, distribution and stranded costs recovery charges;

deregulating the Companies electric generation businesses;

continuing regulation of the Companies transmission and distribution systems; and requiring corporate separation of regulated and unregulated business activities.

However, despite these similarities, the specific approach taken by each state and for each of the Companies varies.

Reliability Initiatives

On October 15, 2003, NERC issued a letter to all NERC control areas and reliability coordinators requesting a review of various reliability practices. The Company response confirmed that its review was completed and that various enhancements were underway to current practices. On February 10, 2004, NERC issued its Recommended Actions to Prevent and Mitigate the Impacts of Future Cascading Blackouts, a portion of which were directed at the FirstEnergy companies and broadly focused on initiatives that were recommended for completion by June 30, 2004. FirstEnergy s detailed implementation plan was endorsed by the NERC Board of Trustees on May 7, 2004. The various initiatives recommended by NERC were certified as complete by June 30, 2004, with one minor exception related to reactive testing of certain generators expected to be completed later in 2004.

On February 26 and 27, 2004, certain FirstEnergy companies, as part of a NERC review of control area operations throughout the United States, participated in a NERC Control Area Readiness Audit. The final audit report, completed on May 6, 2004, identified positive observations and included various recommendations for reliability improvement. FirstEnergy reported completion of those recommendations on June 30, 2004, with one exception related to MISO s implementation of a voltage stability tool expected to be completed later this year.

On April 5, 2004, the U.S. - Canada Power System Outage Task Force issued a Final Report on the August 14, 2003 power outages. The Final Report contains 46 recommendations to prevent or minimize the scope of future blackouts. Forty-five of those recommendations relate to broad industry or policy matters while one, including subparts, relates to activities the Task Force recommended be undertaken by FirstEnergy, MISO, PJM and ECAR. FirstEnergy completed the Task Force recommendations that were directed toward FirstEnergy and reported completion of those activities on June 30, 2004.

With respect to each of the foregoing initiatives, FirstEnergy requested and NERC provided, a technical assistance team of experts to provide ongoing guidance and assistance in implementing and confirming timely and successful completion. NERC further assembled an independent verification team to confirm implementation of the foregoing initiatives required to be completed as of June 30, 2004. The NERC Verification Team reported, on July 14, 2004, that FirstEnergy has completed the recommended policies, procedures and actions required to be completed by June 30, 2004 or summer 2004, with exceptions noted by FirstEnergy. Implementation of the recommendations has not required incremental material investment or upgrades to existing equipment.

On March 1, 2004, certain FirstEnergy companies filed, in accordance with a November 25, 2003 order from the PUCO, their plan for addressing certain issues identified by the PUCO from the U.S. Canada Power System Outage Task Force interim report. In particular, the filing addressed upgrades to FirstEnergy s control room computer hardware and software and enhancements to the training of control room operators. The PUCO will review the plan before determining the next steps, if any, in the proceeding.

On April 22, 2004, FirstEnergy filed with the FERC the results of the FERC-ordered independent study of part of Ohio s power grid. The study examined, among other things, the reliability of the transmission grid in critical points in the Northern Ohio area and the need, if any, for reactive power reinforcements during summers 2004 and 2009. Certain requested additional clarifications were provided to the FERC in October 2004. FirstEnergy completed the implementation of recommendations relating to 2004 by June 30, 2004, and is continuing to review results related to 2009. The estimated capital expenditures required by 2009 are not expected to have a material adverse effect on FirstEnergy s financial results. FirstEnergy notes, however, that the FERC or other applicable government agencies and reliability coordinators may take a different view as to recommended enhancements or may recommend additional enhancements in the future that could require additional, material expenditures.

In late 2003, the PPUC issued a Tentative Order implementing new reliability benchmarks and standards. In connection therewith, the PPUC commenced a rulemaking procedure to amend the Electric Service Reliability Regulations to implement these new benchmarks, and required additional reporting on reliability. The PPUC ordered all Pennsylvania utilities to begin filing quarterly reports on November 1, 2003. On May 11, 2004, the PPUC issued an order approving the revised reliability benchmark and standards, including revised benchmarks and standards for Met-Ed, Penelec and Penn. The Order permitted Pennsylvania utilities to file in a separate proceeding to revise the recomputed benchmarks and standards if they have evidence, such as the impact of automated outage management systems, on the accuracy of the PPUC computed reliability indices. Met-Ed, Penelec and Penn filed a Petition for Amendment of Benchmarks with the PPUC on May 26, 2004 seeking amendment of the benchmarks and standards due to their implementation of automated outage management systems following restructuring. No procedural schedule or hearing date has been set for this proceeding. FirstEnergy is unable to predict the outcome of this proceeding.

On January 16, 2004, the PPUC initiated a formal investigation of whether Met-Ed s, Penelec s and Penn s service reliability performance deteriorated to a point below the level of service reliability that existed prior to restructuring in Pennsylvania. Hearings were held in early August 2004. On September 30, 2004, Met-Ed, Penelec and Penn filed a settlement agreement with the PPUC that addresses the issues related to this investigation. As part of the settlement, Met-Ed, Penelec and Penn agreed to enhance service reliability, performance reporting and communications with customers and to collectively maintain their current spending levels of at least $255 million annually on combined capital and operation and maintenance expenditures for transmission and distribution for the years 2005 through 2007. In November 2004, the PPUC accepted the recommendation of the ALJ approving the settlement.

Ohio

In July 1999, Ohio s electric utility restructuring legislation, which allowed Ohio electric customers to select their generation suppliers beginning January 1, 2001, was signed into law. Among other things, the legislation provided for a 5% reduction on the generation portion of residential customers bills and the opportunity to recover transition costs, including regulatory assets, from January 1, 2001 through December 31, 2005 (market development period). The period for the recovery of regulatory assets only can be extended up to December 31, 2010. The recovery period extension is related to the customer shopping incentives recovery discussed below. The PUCO was authorized to determine the level of transition cost recovery, as well as the recovery period for the regulatory assets portion of those costs, in considering each Ohio electric utility s transition plan application.

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In July 2000, the PUCO approved FirstEnergy s transition plan for the Ohio Companies as modified by a settlement agreement with major parties to the transition plan. The application of SFAS 71 to OE s generation business and the nonnuclear generation businesses of CEI and TE was discontinued with the issuance of the PUCO transition plan order, as described further below. Major provisions of the settlement agreement consisted of approval of recovery of generation-related transition costs as filed of $4.0 billion net of deferred income taxes (OE $1.6 billion, CEI $1.6 billion and TE $0.8 billion) and transition costs related to regulatory assets as filed of $2.9 billion net of deferred income taxes (OE $1.0 billion, CEI $1.4 billion and TE $0.5 billion), with recovery through no later than 2006 for OE, mid-2007 for TE and 2008 for CEI, except where a longer period of recovery is provided for in the settlement agreement. The generation-related transition costs include $1.4 billion, net of deferred income taxes, (OE $1.0 billion, CEI $0.2 billion and TE $0.2 billion) of impaired generating assets recognized as regulatory assets as described further below, $2.4 billion, net of deferred income taxes, (OE $1.2 billion, CEI $0.4 billion and TE $0.8 billion) of above market operating lease costs and $0.8 billion, net of deferred income taxes, (CEI $0.5 billion and TE $0.3 billion) of additional plant costs that were reflected on CEI s and TE s regulatory financial statements.

Also as part of the settlement agreement, FirstEnergy gives preferred access over its subsidiaries to nonaffiliated marketers, brokers and aggregators to 1,120 MW of generation capacity through 2005 at established prices for sales to the Ohio Companies retail customers. Customer prices are frozen through the five-year market development period, which runs through the end of 2005, except for certain limited statutory exceptions, including the 5% reduction referred to above.

FirstEnergy s Ohio customers choosing alternative suppliers receive an additional incentive applied to the shopping credit (generation component) of 45% for residential customers, 30% for commercial customers and 15% for industrial customers. The amount of the incentive is deferred for future recovery from customers through an extension of the regulatory transition charge. Under the modified Rate Stabilization Plan described below, the deferred incentives and deferred interest costs related to the incentives will be amortized on a dollar-for-dollar basis as the associated revenues are recognized.

On October 21, 2003, the Ohio Companies filed an application with the PUCO to establish generation service rates beginning January 1, 2006, in response to expressed concerns by the PUCO about price and supply uncertainty following the end of the market development period. The filing included two options:

- A competitive auction, which would establish a price for generation that customers would be charged during the period covered by the auction, or

- A Rate Stabilization Plan, which would extend current generation prices through 2008, ensuring adequate generation supply at stable prices, and continuing the Ohio Companies support of energy efficiency and economic development efforts.

Under that proposal, the Ohio Companies requested:

- Extension of the transition cost amortization period for OE from 2006 to 2007; for CEI from 2008 to 2009 and for TE from mid-2007 to 2008;

- Deferral of interest costs on the accumulated shopping incentives and other cost deferrals as new regulatory assets; and

- Ability to initiate a request to increase generation rates under certain limited conditions.

On February 23, 2004, after consideration of the PUCO Staff comments and testimony as well as those provided by some of the intervening parties, the Ohio Companies made certain modifications to the Rate Stabilization Plan. On June 9, 2004, the PUCO issued an order approving the revised Rate Stabilization Plan, subject to conducting a competitive bid process on or before December 1, 2004. In addition to requiring the competitive bid process, the PUCO made other modifications to the Ohio Companies revised Rate Stabilization Plan application. Among the major modifications were the following:

Limiting the ability of the Ohio Companies to request adjustments in generation charges during 2006 through 2008 for increases in taxes;

Expanding the availability of market support generation;

Revising the kilowatt-hour target level and the time period for recovering regulatory transition charges;

Establishing a 3-year competitive bid process for generation;

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Establishing the 2005 generation credit for shopping customers, which would be extended as a cap through 2008; and

Denying the ability to defer costs for future recovery of distribution reliability improvement expenditures.

On June 18, 2004, the Ohio Companies filed with the PUCO an application for rehearing of the modified version of the Rate Stabilization Plan. Several other parties also filed applications for rehearing. On August 4, 2004, the PUCO issued an Entry on Rehearing modifying its June 9, 2004 Order. The modifications included the following:

Expanding the Ohio Companies ability to request adjustments in generation charges during 2006 through 2008 to include increases in the cost of fuel (including the cost of emission allowances consumed, lime, stabilizers and other additives and fuel disposal) using 2002 as the base year. Any increases in fuel costs would be subject to downward adjustments in subsequent years should fuel costs decline, but not below the generation rate initially established in the Rate Stabilization Plan;

Approving the revised kilowatt-hour target level and time period for recovery of regulatory transition costs as presented by the Ohio Companies in their rehearing application;

Retaining the requirement for expanded availability of market support generation, but adopting the Ohio Companies alternative approach that conditions expanded availability on higher pricing and eliminating the requirement to reduce the interest deferral for certain affected rate schedules;

Revising the calculation of the shopping credit cap for certain commercial and small industrial rate schedules; and

Relaxing the notice requirement for availability of enhanced shopping credits in a number of instances.

On August 5, 2004, the Ohio Companies accepted the Rate Stabilization Plan as modified and approved by the PUCO on August 4, 2004. The Ohio Companies retain the right to withdraw the modified Rate Stabilization Plan should subsequent adverse action be taken by the PUCO or a court. In the second quarter of 2004, the Ohio Companies implemented the accounting modifications contained in the PUCO s June 9, 2004 Order, which are consistent with the PUCO s August 4, 2004 Entry on Rehearing. Those modifications included amortization of transition costs based on extended amortization periods (that are no later than 2007 for OE, mid-2009 for CEI and mid-2008 for TE) and the deferral of interest costs on the accumulated deferred shopping incentives. On October 1, 2004, the OCC filed an appeal with the Ohio Supreme Court to overturn the June 9, 2004 PUCO order.

The Ohio Companies filed a proposed competitive bid process which the PUCO modified on October 6, 2004. The PUCO approved the rules for the competitive bid process setting a three-year supply period (2006-2008) requirement for generation service suppliers and a load cap for individual suppliers. In mid-October, the initial auction schedule was revised so that Part 1 and Part 2 auction bidder applications are due November 4, 2004 and November 15, respectively, the trial auction is scheduled to occur on December 3, the auction would commence December 8 and the PUCO will accept or reject auction results within two business days after the completion of the auction. FirstEnergy has elected to not participate in the auction.

Transition Cost Amortization

OE, CEI and TE amortize transition costs (see Regulatory Matters Ohio) using the effective interest method. Under the Rate Stabilization Plan as approved above, total transition cost amortization is expected to approximate the following for 2004 through 2009:

	FirstEnergy	OE	CEI	TE
		(In millions)		
2004	$754	$429	$200	$125
2005	841	475	225	141
2006	390	182	124	84
2007	315	85	141	89
2008	160		160	
2009	45		45	

The Ohio Companies are deferring customer shopping incentives and interest costs as new regulatory assets in accordance with the transition and rate stabilization plans. These regulatory assets totaling $556 million as of September 30, 2004 (OE - $205 million, CEI - $271 million, TE - $80 million) will be recovered through a surcharge rate equal to the RTC rate in effect when the transition costs have been fully recovered. Recovery of the new regulatory

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assets will begin at that time and amortization of the regulatory assets for each accounting period will be equal to the surcharge revenue recognized in each period.

New Jersey

JCP&L s 2001 Final Decision and Order (Final Order) with respect to its rate unbundling, stranded cost and restructuring filings confirmed rate reductions set forth in its 1999 Summary Order, which had been in effect at increasing levels through July 2003. The Final Order also confirmed the establishment of a non-bypassable SBC to recover costs which include nuclear plant decommissioning and manufactured gas plant remediation, as well as a non-bypassable MTC primarily to recover stranded costs. The NJBPU has deferred making a final determination of the net proceeds and stranded costs related to prior generating asset divestitures until JCP&L s request for an IRS ruling regarding the treatment of associated federal income tax benefits is acted upon. Should the IRS ruling support the return of the tax benefits to customers, there would be no effect to FirstEnergy s or JCP&L s net income since the contingency existed prior to the merger and there would be an adjustment to goodwill.

In addition, the Final Order provided for the ability to securitize stranded costs associated with the divested Oyster Creek Nuclear Generating Station. Under NJBPU authorization in 2002, JCP&L issued through its wholly owned subsidiary, JCP&L Transition, $320 million of transition bonds (recognized as long-term debt on FirstEnergy s and JCP&L s Consolidated Balance Sheets) which securitized the recovery of these costs and which provided for a usage-based non-bypassable TBC to cover debt service on the bonds.

Prior to August 1, 2003, JCP&L s PLR obligation to provide BGS to non-shopping customers was supplied almost entirely from contracted and open market purchases. JCP&L is permitted to defer for future collection from customers the amounts by which its costs of supplying BGS to non-shopping customers and costs incurred under NUG agreements exceed amounts collected through BGS and MTC rates. As of September 30, 2004, the accumulated deferred cost balance totaled approximately $404 million, after the charge discussed below. The NJBPU also allowed securitization of JCP&L s deferred balance to the extent permitted by law upon application by JCP&L and a determination by the NJBPU that the conditions of the New Jersey restructuring legislation are met. There can be no assurance as to the extent, if any, that the NJBPU will permit such securitization.

Under New Jersey transition legislation, all electric distribution companies were required to file rate cases to determine the level of unbundled rate components to become effective August 1, 2003. JCP&L s two August 2002 rate filings requested increases in base electric rates of approximately $98 million annually and requested the recovery of deferred energy costs that exceeded amounts being recovered under the current MTC and SBC rates; one proposed method of recovery of these costs is the securitization of the deferred balance. This securitization methodology is similar to the Oyster Creek securitization. On July 25, 2003, the NJBPU announced its JCP&L base electric rate proceeding decision, which reduced JCP&L s annual revenues by approximately $62 million effective August 1, 2003. The NJBPU decision also provided for an interim return on equity of 9.5% on JCP&L s rate base for the subsequent six to twelve months. During that period, the decision also required that, within approximately one year of its issuance, JCP&L would initiate another proceeding to request recovery of additional costs incurred to enhance system reliability. In that Phase II proceeding, the NJBPU could increase JCP&L s return on equity to 9.75% or decrease it to 9.25%, depending on its assessment of the reliability of JCP&L s service. Any reduction would be retroactive to August 1, 2003. The net revenue decrease from the NJBPU s decision consists of a $223 million decrease in the electricity delivery charge, a $111 million increase due to the August 1, 2003 expiration of annual customer credits previously mandated by the New Jersey transition legislation, a $49 million increase in the MTC tariff component, and a net $1 million increase in the SBC. The decision in the deferred balances proceeding disallowed $153 million of deferred energy costs, so that the MTC allows for the recovery of $465 million in deferred energy costs over the next ten years on an interim basis. As a result, JCP&L recorded charges to net income for the year ended December 31, 2003, aggregating $185 million ($109 million net of tax) consisting of the $153 million of disallowed deferred energy costs and $32 million of other disallowed regulatory assets. JCP&L filed an interim motion for rehearing and reconsideration with the NJBPU on August 15, 2003 with respect to the following issues: (1) the disallowance of the $153 million deferred energy costs; (2) the reduced rate of return on equity; and (3) $42.7 million of disallowed costs to achieve merger savings. In its final decision and order issued on May 17, 2004, the NJPBU clarified the method for calculating interest attributable to the cost disallowances, resulting in a $5.4 million reduction from the amount estimated in 2003. On June 1, 2004, JCP&L filed with the NJBPU a supplemental and amended motion for rehearing and reconsideration. On July 7, 2004, the NJBPU granted limited reconsideration and rehearing on the following issues: (1) deferred cost disallowances, (2) the capital structure including the rate of return, (3) merger savings, including amortization of costs to achieve merger savings; and (4) decommissioning. All other issues included in JCP&L s amended motion were denied. Oral arguments were held on August 4, 2004. Management is unable to predict when a decision may be reached by the NJBPU.

On July 5, 2003, JCP&L experienced a series of 34.5 kilovolt sub-transmission line faults that resulted in outages on the New Jersey shore. The NJBPU instituted an investigation into these outages, and directed that a Special Reliability Master (SRM) be hired to oversee the investigation. On December 8, 2003, the SRM issued his Interim Report recommending that JCP&L implement a series of actions to improve reliability in the area affected by the outages. The

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NJBPU adopted the findings and recommendations of the Interim Report on December 17, 2003, and ordered JCP&L to implement the recommended actions on a staggered basis, with initial actions to be completed by March 31, 2004. In late 2003, in accordance with a Settlement Stipulation concerning an August 2002 storm outage, the NJBPU engaged Booth & Associates to conduct an audit of the planning, operations and maintenance practices, policies and procedures of JCP&L. The audit was expanded to include the July 2003 outage and was completed in January 2004. On June 9, 2004, the NJBPU approved a stipulation that incorporated the final SRM report and portions of the final Booth report. The final order was issued by the NJBPU on July 23, 2004.

On July 16, 2004, JCP&L filed the Phase II rate filing with the NJBPU which requested an increase in base rates of $36 million, reflecting the recovery of system reliability costs and a 9.75% return on equity. The filing also requests an increase to the MTC deferred balance recovery of approximately $20 million annually. Discovery/settlement conferences are ongoing. The filing fulfills the NJBPU requirement that a Phase II proceeding be conducted and that any expenditures and projects undertaken by JCP&L to increase its system reliability be reviewed.

JCP&L sells all self-supplied energy (NUGs and owned generation) to the wholesale market with offsetting credits to its deferred energy balances with the exception of 300 MW from JCP&L s must run NUG committed supply currently being used to serve BGS customers pursuant to NJBPU order. The BGS auction for periods beginning June 1, 2004 was completed in February 2004 and new BGS tariffs reflecting the auction results became effective June 1, 2004. On May 25, 2004, the NJBPU issued an order adopting a schedule for the BGS post transition year three process. JCP&L filed its proposal suggesting how BGS should be procured for year three and beyond. The NJBPU decision on the filing was announced on October 22, 2004, approving with minor modifications the BGS procurement process filed by JCP&L and the other New Jersey electric distribution companies and authorizing the continued use of NUG committed supply to serve 300 MW of BGS load. The auction is scheduled to take place in February 2005 for the supply period beginning June 1, 2005.

In accordance with an April 28, 2004 NJBPU order, JCP&L filed testimony on June 7, 2004 supporting a continuation of the current level and duration of the funding of TMI-2 decommissioning costs by New Jersey ratepayers without a reduction, termination or capping of the funding. On September 30, 2004, JCP&L filed an updated TMI-2 decommissioning study prepared by TLG Services, Inc. (see Note 2 Asset Retirement Obligations). This study resulted in an updated total decommissioning cost estimate of $729 million (in 2003 dollars) compared to the estimated $528 million (in 2003 dollars) from the prior 1995 decommissioning study.

Pennsylvania

The PPUC authorized in 1998 rate restructuring plans for Penn, Met-Ed and Penelec. In 2000, the PPUC disallowed a portion of the requested additional stranded costs above those amounts granted in Met-Ed s and Penelec s 1998 rate restructuring plan orders. The PPUC required Met-Ed and Penelec to seek an IRS ruling regarding the return of certain unamortized investment tax credits and excess deferred income tax benefits to customers. Similar to JCP&L s situation, if the IRS ruling ultimately supports returning these tax benefits to customers, there would be no effect to FirstEnergy s, Met-Ed s or Penelec s net income since the contingency existed prior to the merger and would be an adjustment to goodwill.

In June 2001, the PPUC approved the Settlement Stipulation with all of the major parties in the combined merger and rate relief proceedings which approved the FirstEnergy/GPU merger and provided PLR deferred accounting treatment for energy costs, permitting Met-Ed and Penelec to defer, for future recovery, energy costs in excess of amounts reflected in their capped generation rates retroactive to January 1, 2001. This PLR deferral accounting procedure was later denied in a February 2002 Commonwealth Court of Pennsylvania decision. The court decision also affirmed the PPUC decision regarding approval of the merger, remanding the decision to the PPUC only with respect to the issue of merger savings. FirstEnergy established reserves in 2002 for Met-Ed s and Penelec s PLR deferred energy costs which aggregated $287.1 million, reflecting the potential adverse impact of the then pending Pennsylvania Supreme Court decision whether to review the Commonwealth Court decision. As a result, FirstEnergy recorded in 2002 an aggregate non-cash charge of $55.8 million ($32.6 million net of tax) to income for the deferred costs incurred subsequent to the merger. The reserve for the remaining $231.3 million of deferred costs increased goodwill by an aggregate net of tax amount of $135.3 million.

On April 2, 2003, the PPUC remanded the issue relating to merger savings to the Office of Administrative Law for hearings, directed Met-Ed and Penelec to file a position paper on the effect of the Commonwealth Court order on the Settlement Stipulation and allowed other parties to file responses to the position paper. Met-Ed and Penelec filed a letter with the ALJ on June 11, 2003, voiding the Settlement Stipulation in its entirety and reinstating Met-Ed s and Penelec s restructuring settlement previously approved by the PPUC.

On October 2, 2003, the PPUC issued an order concluding that the Commonwealth Court reversed the PPUC s June 20, 2001 order in its entirety. The PPUC directed Met-Ed and Penelec to file tariffs within thirty days of the order to reflect the CTC rates and shopping credits that were in effect prior to the June 21, 2001 order to be effective upon one day s notice. In response to that order, Met-Ed and Penelec filed supplements to their tariffs to become effective October 24, 2003.

On October 8, 2003, Met-Ed and Penelec filed a petition for clarification relating to the October 2, 2003 order on two issues: to establish June 30, 2004 as the date to fully refund the NUG trust fund and to clarify that the ordered accounting treatment regarding the CTC rate/shopping credit swap should follow the ratemaking, and that the PPUC s findings would not impair their rights to recover all of their stranded costs. On October 9, 2003, ARIPPA (an intervenor in the proceedings) petitioned the PPUC to direct Met-Ed and Penelec to reinstate accounting for the CTC rate/shopping credit swap retroactive to January 1, 2002. Several other parties also filed petitions. On October 16, 2003, the PPUC issued a reconsideration order granting the date requested by Met-Ed and Penelec for the NUG trust fund refund, denying Met-Ed s and Penelec s other clarification requests and granting ARIPPA s petition with respect to the accounting treatment of the changes to the CTC rate/shopping credit swap. On October 22, 2003, Met-Ed and Penelec filed an Objection with the Commonwealth Court asking that the Court reverse the PPUC s finding that requires Met-Ed and Penelec to treat the stipulated CTC rates that were in effect from January 1, 2002 on a retroactive basis.

On October 27, 2003, a Commonwealth Court judge issued an Order denying Met-Ed s and Penelec s Objection without explanation. Due to the vagueness of the Order, Met-Ed and Penelec, on October 31, 2003, filed an Application for Clarification with the judge. Concurrent with this filing, Met-Ed and Penelec, in order to preserve their rights, also filed with the Commonwealth Court both a Petition for Review of the PPUC s October 2 and October 16 Orders, and an application for reargument, if the judge, in his clarification order, indicates that Met-Ed s and Penelec s Objection was intended to be denied on the merits. In addition to these findings, Met-Ed and Penelec, in compliance with the PPUC s Orders, filed revised PPUC quarterly reports for the twelve months ended December 31, 2001 and 2002, and for the first two quarters of 2003, reflecting balances consistent with the PPUC s findings in their Orders.

Met-Ed and Penelec purchase a portion of their PLR requirements from FES through a wholesale power sale agreement. The PLR sale is automatically extended for each successive calendar year unless any party elects to cancel the agreement by November 1 of the preceding year. Under the terms of the wholesale agreement, FES retains the supply obligation and the supply profit and loss risk, for the portion of power supply requirements not self-supplied by Met-Ed and Penelec under their NUG contracts and other power contracts with nonaffiliated third party suppliers. This arrangement reduces Met-Ed s and Penelec s exposure to high wholesale power prices by providing power at a fixed price for their uncommitted PLR energy costs during the term of the agreement with FES. FES has hedged most of Met-Ed s and Penelec s unfilled PLR on-peak obligation through 2004 and a portion of 2005, the period during which deferred accounting was previously allowed under the PPUC s order. Met-Ed and Penelec are authorized to continue deferring differences between NUG contract costs and current market prices.

7 - NEW ACCOUNTING STANDARDS AND INTERPRETATIONS:

Exposure Draft of Proposed Statement of Financial Accounting Standards Share-Based Payment an amendment of FASB Statements No. 123 and 95

In March 2004, the FASB issued an exposure draft of a new standard, which would amend SFAS 123 and SFAS 95. Among other items, the new standard would require expensing stock options in FirstEnergy s financial statements. In October 2004, the FASB agreed to delay the effective date of the proposed standard from January 1, 2005 to periods beginning after June 15, 2005, for calendar year companies. FirstEnergy will not be able to determine the impact of the proposed standard on its results of operations until the standard is issued in final form. The impacts of the fair value recognition provisions of SFAS 123 on FirstEnergy s net income and earnings per share for the current reporting periods are disclosed in Note 2.

Exposure Draft of Proposed Statement of Financial Accounting Standards Earnings per Share an amendment of FASB Statement No. 128

In December 2003, the FASB issued an exposure draft of a new standard, which would amend SFAS 128. Among other items, the new standard would eliminate the provisions of SFAS 128 that allow an entity to rebut the presumption that contracts with the option of settling in either cash or stock will be settled in stock. The new standard is expected to be issued in the fourth quarter of 2004 and be effective for all periods ending after December 15, 2004. Retrospective application to all prior-period earnings per share data presented would be required. FirstEnergy is continuing to assess the proposed standard but does not anticipate a material impact on its calculation of earnings per share.

EITF Issue No. 03-1, The Meaning of Other-Than-Temporary and Its Application to Certain Investments

In March 2004, the EITF reached a consensus on the application guidance for Issue 03-1. EITF 03-1 provides a model for determining when investments in certain debt and equity securities are considered other than temporarily impaired. When an impairment is other-than-temporary, the investment must be measured at fair value and the impairment loss recognized in earnings. The recognition and measurement provisions of EITF 03-1, which were to be effective for periods beginning after June 15, 2004, were delayed by the issuance of FSP EITF 03-1-1 in September 2004. During the period of delay, FirstEnergy will continue to evaluate its investments as required by existing authoritative guidance.

EITF Issue No. 03-16, Accounting for Investments in Limited Liability Companies

In March 2004, the FASB ratified the final consensus on Issue 03-16. EITF 03-16 requires that an investment in a limited liability company that maintains a specific ownership account for each investor should be viewed as similar to an investment in a limited partnership for determining whether the cost or equity method of accounting should be used. The equity method of accounting is generally required for investments that represent more than a three to five percent interest in a limited partnership. EITF 03-16 was adopted by FirstEnergy in the third quarter of 2004 and did not affect the Companies financial statements.

FSP 106-2, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003

Issued in May 2004, FSP 106-2 provides guidance on accounting for the effects of the Medicare Act for employers that sponsor postretirement health care plans that provide prescription drug benefits. FSP 106-2 also requires certain disclosures regarding the effect of the federal subsidy provided by the Medicare Act. The effect of the federal subsidy provided under the Medicare Act on FirstEnergy s consolidated financial statements is described in Note 4. The impact of the subsidy was not material to the financial statements of each of the Companies for the three and nine months ended September 30, 2004.

FIN 46 (revised December 2003), Consolidation of Variable Interest Entities

In December 2003, the FASB issued a revised interpretation of ARB 51 referred to as FIN 46R, which requires the consolidation of a VIE by an enterprise if that enterprise is determined to be the primary beneficiary of the VIE. As required, FirstEnergy adopted FIN 46R for interests in VIEs commonly referred to as special-purpose entities effective December 31, 2003 and for all other types of entities effective March 31, 2004. Adoption of FIN 46R did not have a material impact on the consolidated financial statements of FirstEnergy or the Companies.

8 - SEGMENT INFORMATION:

FirstEnergy operates under two reportable segments: regulated services and competitive services. The aggregate Other segments do not individually meet the criteria to be considered a reportable segment. Other consists of interest expense related to holding company debt; corporate support services and the international businesses acquired in the 2001 merger. FirstEnergy s primary segment is its regulated services segment, whose operations include the regulated sale of electricity and distribution and transmission services by its eight EUOC in Ohio, Pennsylvania and New Jersey. The competitive services business segment consists of the subsidiaries (FES, FSG, MYR and FirstCom) that operate unregulated energy and energy-related businesses, including the operation of FirstEnergy s generation facilities resulting from the deregulation of the Companies electric generation business (see Note 6 Regulatory Matters). The regulated services segment designs, constructs, operates and maintains FirstEnergy s regulated transmission and distribution systems. Its revenues are primarily derived from electricity delivery and transition costs recovery.

The competitive services segment has responsibility for FirstEnergy generation operations as discussed under Note 6. As a result, its revenues include all generation electric sales revenues (including the generation services to regulated franchise customers who have not chosen an alternative generation supplier) and all domestic unregulated energy and energy-related services including commodity sales (both electricity and natural gas) in the retail and wholesale markets, marketing, generation and sourcing of commodity requirements, providing local and long-distance phone service, as well as other competitive energy-application services.

Segment reporting in 2003 was reclassified to conform with the current year business segment organizations and operations. Revenues from the competitive services segment now include all generation revenues including generation services to regulated franchise customers previously reported under the regulated services segment and now exclude revenues from power supply agreements with the regulated services segment previously reported as internal revenues. The regulated services segment results now exclude generation sales revenues and related generation commodity costs. Certain amounts (including transmission and congestion charges) were reclassified among purchased power, other operating costs and depreciation and amortization to conform with the current year presentation of generation commodity costs. Segment results for 2003 have been adjusted to reflect the reclassification of revenue, expense, interest expense and tax amounts of divested businesses reflected as discontinued operations (see Note 2) and certain revenues and expenses have been reclassified and presented on a net basis to conform with the current year presentation (see Note 1).

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Segment Financial Information

	Regulated Services	Competitive Services	Other	Reconciling Adjustments	Consolidated
			(In millions)		
Three Months Ended:					
September 30, 2004					
External revenues	$ 1,480	$ 2,064	$ 1	$ (9)(a)	$ 3,536
Internal revenues			106	(106)(b)	
Total revenues	1,480	2,064	107	(115)	3,536
Depreciation and amortization	375	9	9		393
Net interest charges	86	10	71	(15)(b)	152
Income taxes	225	33	(42)		216
Net income (loss)	315	47	(63)		299
Total assets	28,416	2,168	641		31,225
Total goodwill	5,965	136			6,101
Property additions	157	47	7		211
September 30, 2003					
External revenues	$ 1,478	$ 1,929	$ 18	$ (2)(a)	$ 3,423
Internal revenues			136	(136)(b)	
Total revenues	1,478	1,929	154	(138)	3,423
Depreciation and amortization	370	8	11		389
Goodwill impairment		117			117
Net interest charges	116	13	54	18(b)	201
Income taxes	213	(43)	(35)		135
Income before discontinued operations and cumulative effect of accounting change	293	(88)	(53)		152
Net income (loss)	293	(86)	(54)		153
Total assets	29,794	2,324	1,377		33,495
Total goodwill	5,993	135			6,128
Property additions	63	88	5		156
Nine Months Ended:					
September 30, 2004					
External revenues	$ 4,047	$ 5,808	$ 13	$ 1(a)	$ 9,869
Internal revenues			354	(354)(b)	
Total revenues	4,047	5,808	367	(353)	9,869
Depreciation and amortization	1,099	27	29		1,155
Net interest charges	301	32	213	(43)(b)	503
Income taxes	540	69	(99)		510
Net income (loss)	760	99	(182)		677
Total assets	28,416	2,168	641		31,225
Total goodwill	5,965	136			6,101
Property additions	377	152	17		546

September 30, 2003					
External revenues	$ 4,005	$ 5,412	$ 51	$ 29(a)	$ 9,497
Internal revenues			406	(406)(b)	
Total revenues	4,005	5,412	457	(377)	9,497
Depreciation and amortization	1,069	22	29		1,120
Goodwill impairment		117			117
Net interest charges	371	37	262	(58)(b)	612
Income taxes	550	(207)	(95)		248
Income before discontinued operations and cumulative effect of accounting change	754	(321)	(157)		276
Net income (loss)	856	(324)	(219)		313
Total assets	29,794	2,324	1,377		33,495
Total goodwill	5,993	135			6,128
Property additions	218	302	60		580

Reconciling adjustments to segment operating results from internal management reporting to consolidated external financial reporting:

(a) Principally fuel marketing revenues which are reflected as reductions to expenses for internal management reporting purposes.

(b) Elimination of intersegment transactions.

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FIRSTENERGY CORP.

CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2004	**2003**	**2004**	**2003**
	(In thousands, except per share amounts)			
REVENUES:				
Electric utilities	$2,526,971	$2,525,758	$6,874,574	$6,924,781
Unregulated businesses	1,009,348	897,056	2,994,092	2,571,869
Total revenues	3,536,319	3,422,814	9,868,666	9,496,650
EXPENSES:				
Fuel and purchased power	1,285,355	1,199,408	3,514,816	3,338,361
Purchased gas	96,836	105,213	353,327	453,824
Other operating expenses	917,345	946,847	2,641,870	2,813,191
Provision for depreciation and amortization	393,218	389,401	1,154,895	1,119,954
Goodwill impairment (Note 2)		116,988		116,988
General taxes	177,452	177,499	514,269	518,451
Total expenses	2,870,206	2,935,356	8,179,177	8,360,769
NET INTEREST CHARGES:				
Interest expense	152,703	199,106	505,448	598,645
Capitalized interest	(6,536)	(6,513)	(18,286)	(23,287)
Subsidiaries preferred stock dividends	5,354	8,021	16,024	36,423
Net interest charges	151,521	200,614	503,186	611,781
INCOME TAXES	215,970	135,151	509,637	247,692
INCOME BEFORE DISCONTINUED OPERATIONS AND CUMULATIVE EFFECT OF ACCOUNTING CHANGE	298,622	151,693	676,666	276,408
Discontinued operations (net of income taxes (benefit) of $(2,361,000) and $216,000 in the 2003 three month and		1,026		(65,222)

nine month periods, respectively) (Note 2)				
Cumulative effect of accounting change (net of income taxes of $72,516,000) (Note 2)				102,147
NET INCOME	$ 298,622	$ 152,719	$ 676,666	$ 313,333
BASIC EARNINGS PER SHARE OF COMMON STOCK:				
Income before discontinued operations and cumulative effect of accounting change	$ 0.91	$ 0.51	$ 2.07	$ 0.93
Discontinued operations (net of income taxes) (Note 2)				(0.22)
Cumulative effect of accounting change (net of income taxes) (Note 2)				0.35
Net income	$ 0.91	$ 0.51	$ 2.07	$ 1.06
WEIGHTED AVERAGE NUMBER OF BASIC SHARES OUTSTANDING	327,499	299,422	327,280	295,825
DILUTED EARNINGS PER SHARE OF COMMON STOCK:				
Income before discontinued operations and cumulative effect of accounting change	$ 0.91	$ 0.50	$ 2.06	$ 0.93
Discontinued operations (net of income taxes) (Note 2)				(0.22)
Cumulative effect of accounting change (net of income taxes) (Note 2)				0.34
Net income	$ 0.91	$ 0.50	$ 2.06	$ 1.05
WEIGHTED AVERAGE NUMBER OF DILUTED SHARES OUTSTANDING	329,099	300,751	328,850	297,153
DIVIDENDS DECLARED PER SHARE OF COMMON STOCK	$ 0.375	$ 0.375	$ 1.125	$ 1.125

The preceding Notes to Consolidated Financial Statements as they relate to FirstEnergy Corp. are an integral part of these statements.

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FIRSTENERGY CORP.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2004	**2003**	**2004**	**2003**
	(In thousands)			
NET INCOME	$298,622	$152,719	$676,666	$313,333
OTHER COMPREHENSIVE INCOME:				
Unrealized gain (loss) on derivative hedges	5,927	(8,133)	26,536	(6,594)
Unrealized gain on available for sale securities	8,715	9,709	5,265	62,261
Currency translation adjustments		(11)		91,450
Other comprehensive income	14,642	1,565	31,801	147,117
Income tax related to other comprehensive income	(2,498)	(41)	(11,026)	(23,529)
Other comprehensive income, net of tax	12,144	1,524	20,775	123,588
COMPREHENSIVE INCOME	$310,766	$154,243	$697,441	$436,921

The preceding Notes to Consolidated Financial Statements as they relate to FirstEnergy Corp. are an integral part of these statements.

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FIRSTENERGY CORP.

CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2004	December 31, 2003
	(In thousands)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 67,892	$ 113,975
Receivables-		
Customers (less accumulated provisions of $48,031,000 and $50,247,000, respectively, for uncollectible accounts)	1,020,756	1,000,259
Other (less accumulated provisions of $28,392,000 and $12,851,000, respectively, for uncollectible accounts)	371,865	505,241
Materials and supplies, at average cost-		
Owned	346,455	325,303
Under consignment	95,728	95,719
Prepayments and other	216,618	202,814
	2,119,314	2,243,311
PROPERTY, PLANT AND EQUIPMENT:		
In service	21,979,434	21,594,746
Less Accumulated provision for depreciation	9,294,783	9,105,303
	12,684,651	12,489,443
Construction work in progress	653,718	779,479
	13,338,369	13,268,922
INVESTMENTS:		
Nuclear plant decommissioning trusts	1,461,893	1,351,650
Investments in lease obligation bonds	966,685	989,425
Certificates of deposit		277,763
Other	726,153	878,853

	3,154,731	3,497,691
DEFERRED CHARGES:		
Regulatory assets	5,792,517	7,076,923
Goodwill	6,100,969	6,127,883
Other	719,216	695,218
	12,612,702	13,900,024
	$31,225,116	$ 32,909,948
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 674,901	$ 1,754,197
Short-term borrowings	302,508	521,540
Accounts payable	575,845	725,239
Accrued taxes	969,622	669,529
Other	959,475	801,662
	3,482,351	4,472,167
CAPITALIZATION:		
Common stockholders equity-		
Common stock, $0.10 par value, authorized 375,000,000 shares- 329,836,276 shares outstanding	32,984	32,984
Other paid-in capital	7,055,997	7,062,825
Accumulated other comprehensive loss	(331,874)	(352,649)
Retained earnings	1,913,305	1,604,385
Unallocated employee stock ownership plan common stock- 2,246,960 and 2,896,951 shares, respectively	(46,002)	(58,204)
Total common stockholders equity	8,624,410	8,289,341
Preferred stock of consolidated subsidiaries not subject to mandatory redemption	335,123	335,123
Long-term debt and other long-term obligations	10,110,552	9,789,066
	19,070,085	18,413,530
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	2,019,446	2,178,075
Asset retirement obligations	1,060,290	1,179,493
Power purchase contract loss liability	2,173,888	2,727,892

Retirement benefits	1,197,903	1,591,006
Lease market valuation liability	957,450	1,021,000
Other	1,263,703	1,326,785
	8,672,680	10,024,251
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 3)		
	$31,225,116	$ 32,909,948

The preceding Notes to Consolidated Financial Statements as they relate to FirstEnergy Corp. are an integral part of these balance sheets.

FIRSTENERGY CORP.

CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2004	2003	2004	2003
	(In thousands)			
CASH FLOWS FROM OPERATING ACTIVITIES:				
Net income	$ 298,622	$ 152,719	$ 676,666	$ 313,333
Adjustments to reconcile net income to net cash from operating activities-				
Provision for depreciation and amortization	393,218	389,401	1,154,895	1,119,954
Nuclear fuel and lease amortization	26,776	16,902	71,782	47,398
Other amortization, net	(6,486)	(9,540)	(13,927)	(6,244)
Deferred costs recoverable as regulatory assets	(118,409)	(93,652)	(263,290)	(302,651)
Deferred income taxes, net	43,991	(40,072)	(37,206)	(60,507)
Investment tax credits, net	(6,853)	(7,349)	(19,789)	(19,855)
Goodwill impairment		116,988		116,988
Accrued retirement benefit obligations	42,397	81,819	106,897	229,172
Accrued compensation, net	26,592	(440)	48,186	(70,976)
Revenue credits to customers		(19,583)		(71,984)
Disallowed regulatory assets				152,500
Cumulative effect of accounting change				(174,663)
Loss (income) from discontinued operations		(1,026)		65,222
Commodity derivative transactions, net	17,336	(34,939)	(37,443)	(31,137)
Pension trust contribution	(500,000)		(500,000)	
Receivables	16,288	104,516	187,730	43,959
Materials and supplies	6,210	19,708	(21,161)	(14,276)
Prepayments and other current assets	33,441	109,687	(16,172)	(10,871)
Accounts payable	(37,049)	(136,271)	(145,691)	(171,314)
Accrued taxes	153,634	188,261	300,430	210,115
Accrued interest	82,576	68,357	76,210	51,898
NUG power contract restructuring	52,800		52,800	
Deferred rents and lease market valuation liability	28,402	(6,401)	(52,182)	(86,363)
Other	11,929	(20,475)	(33,447)	(24,765)
Net cash provided from operating activities	565,415	878,610	1,535,288	1,304,933
CASH FLOWS FROM FINANCING ACTIVITIES:				
New Financing-				
Common Stock		934,605		934,605
Long-term debt	86,754		961,474	771,637

Redemptions and Repayments-				
Preferred stock	(1,000)	(1,000)	(1,000)	(126,337)
Long-term debt	(772,451)	(569,273)	(1,752,394)	(1,337,205)
Short-term borrowings, net	228,072	(798,985)	(219,032)	(846,734)
Net controlled disbursement activity	(19,129)	(2,369)	(36,400)	31,352
Common stock dividend payments	(123,965)	(110,373)	(367,751)	(330,816)
Net cash used for financing activities	(601,719)	(547,395)	(1,415,103)	(903,498)
CASH FLOWS FROM INVESTING ACTIVITIES:				
Property additions	(211,243)	(155,908)	(545,743)	(580,069)
Nonutility generation trust withdrawals (contributions)			(50,614)	106,327
Contribution to nuclear decommissioning trusts	(25,370)	(47,622)	(76,112)	(75,873)
Proceeds from asset sales	1,662	1,081	213,109	67,530
Proceeds from note receivable				19,000
Cash investments	(7,316)	31,696	19,640	46,761
Proceeds from certificates of deposit	277,763		277,763	
Other	(30,838)	(48,124)	(4,311)	28,851
Net cash provided from (used for) investing activities	4,658	(218,877)	(166,268)	(387,473)
Net increase (decrease) in cash and cash equivalents	(31,646)	112,338	(46,083)	13,962
Cash and cash equivalents at beginning of period	99,538	127,556	113,975	225,932
Cash and cash equivalents at end of period	$ 67,892	$ 239,894	$ 67,892	$ 239,894

The preceding Notes to Consolidated Financial Statements as they relate to FirstEnergy Corp. are an integral part of these statements.

Report of Independent Registered Public Accounting Firm

To the Stockholders and Board of
Directors of FirstEnergy Corp.:

We have reviewed the accompanying consolidated balance sheet of FirstEnergy Corp. and its subsidiaries as of September 30, 2004, and the related consolidated statements of income, comprehensive income and cash flows for each of the three-month and nine-month periods ended September 30, 2004 and 2003. These interim financial statements are the responsibility of the Company s management.

We conducted our review in accordance with the standards of the Public Company Accounting Oversight Board (United States). A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the Public Company Accounting Oversight Board, the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to the accompanying consolidated interim financial statements for them to be in conformity with accounting principles generally accepted in the United States of America.

We previously audited in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet and the consolidated statement of capitalization as of December 31, 2003, and the related consolidated statements of income, common stockholders equity, preferred stock, cash flows and taxes for the year then ended (not presented herein), and in our report (which contained references to the Company s change in its method of accounting for asset retirement obligations as of January 1, 2003 as discussed in Note 2(F) to those consolidated financial statements and the Company s change in its method of accounting for the consolidation of variable interest entities as of December 31, 2003 as discussed in Note 9 to those consolidated financial statements) dated February 25, 2004 we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying consolidated balance sheet as of December 31, 2003, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

PricewaterhouseCoopers LLP
Cleveland, Ohio
November 2, 2004

FIRSTENERGY CORP.

**MANAGEMENT S DISCUSSION AND ANALYSIS OF
RESULTS OF OPERATIONS AND FINANCIAL CONDITION**

EXECUTIVE SUMMARY

Net income in the third quarter of 2004 was $299 million, or basic and diluted earnings of $0.91 per share of common stock, compared to net income of $153 million, or basic earnings of $0.51 per share of common stock ($0.50 diluted) for the third quarter of 2003. FirstEnergy s third quarter earnings reflect solid progress particularly in the areas of lower financing costs and improvements in power generation and energy delivery operations. Net income in the first nine months of 2004 was $677 million, or basic earnings of $2.07 per share ($2.06 diluted), compared to $313 million, or basic earnings of $1.06 per share ($1.05 diluted) for the first nine months of 2003. Earnings in the third quarter and first nine months of 2004 were reduced on a per share basis from the issuance and sale of 32.2 million shares of common stock in the third quarter of 2003. The additional shares reduced earnings by $0.09 per share of common stock (basic and diluted) in the third quarter of 2004 and reduced basic and diluted earnings by $0.22 per share of common stock in the first nine months of 2004.

Milder weather during the third quarter of 2004 led to overall flat kilowatt-hour deliveries compared with the year-prior quarter, including a negative impact on residential customers because of lower air-conditioning use. Despite the milder weather, FirstEnergy s generation fleet continued to show improved performance, enabling FirstEnergy to take advantage of additional spot market sales. The fleet posted a record output in the third quarter and the first nine months of 2004.

FirstEnergy s pension and other post-employment benefits expenses decreased by $29 million in the third quarter of 2004 compared to the same period last year, due to higher trust asset values, revisions to its health care benefits plan, and the positive effect from the new Medicare Act enacted in December 2003. The same factors contributed to a $77 million decrease in the first nine months of 2004, compared to the same period in 2003.

FirstEnergy s debt paydown and refinancing program reduced debt by $982 million during the first nine months of 2004 which is expected to produce annualized savings of approximately $79 million. FirstEnergy remains on track to achieve its goal of reducing debt by at least $1 billion this year. FirstEnergy also improved its financial flexibility with the replacement of $1 billion of its credit commitments that, combined with other existing credit facilities, brings the total capacity of FirstEnergy s primary credit facilities and those of its subsidiaries to $2.3 billion.

On August 5, 2004, the Ohio Companies accepted the Ohio Rate Stabilization Plan as modified and approved by the PUCO on August 4, 2004. In addition to providing enhanced customer benefits, the approved plan adequately addressed most of the issues raised by FirstEnergy. Those issues included the ability to seek recovery of increased fuel costs and terms for offering market support generation. In the second quarter of 2004, FirstEnergy implemented the accounting modifications approved by the PUCO in its initial Rate Stabilization Plan order. On October 1, 2004, the OCC filed an appeal with the Ohio Supreme Court to overturn the June 9, 2004 PUCO order.

The Ohio Companies filed a proposed competitive bid process which the PUCO modified on October 6, 2004. The PUCO approved the rules for the competitive bid process setting a three-year supply period (2006-2008) requirement for generation service suppliers and a load cap for individual suppliers. In mid-October, the initial auction schedule was revised so that Part 1 and Part 2 auction bidder applications are due November 4, 2004 and November 15, respectively, the trial auction is scheduled to occur on December 3, the auction commences December 8 and the PUCO will accept or reject auction results within two business days after the completion of the auction.

FirstEnergy has elected to not participate in the auction.

In September 2004, FirstEnergy and its subsidiaries made a $500 million voluntary contribution to their pension plan to eliminate funding requirements that were projected in 2006 and 2007. The net after-tax cost of the contribution is approximately $300 million and is expected to be accretive to earnings over the next three years. In addition, the contribution is expected to reduce FirstEnergy s overall risk profile, because it reduces uncertainty regarding the plan s unfunded liability.

On July 27, 2004, FirstEnergy announced that it had reached an agreement to resolve various pending legal proceedings filed against FirstEnergy and certain of its officers and directors, alleging violations of federal securities laws and related state laws (see Outlook Other Legal Matters below) in connection with financial restatements of previously reported results in August 2003, by FirstEnergy and the Ohio Companies, the August 14, 2003 regional power outages and the extended outage at the Davis-Besse Nuclear Power Station. The settlement agreement, which does not constitute an admission of wrongdoing, provides for a total settlement payment of $89.9 million, of which

FirstEnergy s insurance carrier will pay $71.92 million. FirstEnergy s portion of $17.98 million, resulted in an after-tax charge of $11 million or $0.03 per share of common stock (basic and diluted) in FirstEnergy s second quarter and year-to-date 2004 earnings. The settlement was preliminarily approved by the court with a final hearing scheduled for mid-December 2004.

FirstEnergy continues to participate in meaningful settlement negotiations with the EPA and other parties to the New Source Review case involving the W. H. Sammis Plant (see Outlook - Environmental Matters). As a result, the U.S. District Court judge hearing the case rescheduled the date for the remedy phase of the trial to January 2005.

FIRSTENERGY S BUSINESS

FirstEnergy Corp. is a registered public utility holding company headquartered in Akron, Ohio that provides regulated and competitive energy services (see Results of Operations Business Segments). FirstEnergy continues to pursue its goal of being the leading supplier of energy and related services in portions of the Midwest and mid-Atlantic regions of the United States, where it sees the best opportunities for growth. FirstEnergy s fundamental business strategy remains stable and unchanged. While FirstEnergy continues to build toward a strong regional presence, key elements for its strategy are in place and management s focus continues to be on execution. FirstEnergy intends to continue providing competitively priced, high-quality products and value-added services energy sales and services, energy delivery, power supply and supplemental services related to its core business. As the industry continues to evolve, FirstEnergy has taken and expects to take actions designed to compete in the changing energy marketplace. FirstEnergy s eight electric utility operating companies provide transmission and distribution services and comprise the nation s fifth largest investor-owned electric system, serving 4.4 million customers within 36,100 square miles of Ohio, Pennsylvania and New Jersey.

Competitive services are principally provided by FES, FSG, MYR and FirstEnergy s majority owned subsidiary, FirstCom. Services provided through these subsidiaries include heating, ventilation, air-conditioning, refrigeration, process piping, plumbing, electrical and facility control systems and high-efficiency electrotechnologies. Telecommunication services such as local and long-distance telephone service are also provided to more than 65,000 customers. While competitive revenues have increased since 2001, regulated energy services continue to provide, in aggregate, the majority of FirstEnergy s revenues and earnings.

Beginning in 2001, Ohio utilities that offered both competitive and regulated retail electric services were required to implement a corporate separation plan approved by the PUCO one which provided a clear separation between regulated and competitive operations. FES provides competitive retail energy services while the EUOC provide regulated transmission and distribution services. FGCO, a wholly owned subsidiary of FES, leases fossil and hydroelectric plants from the EUOC and operates those plants. Under the terms of the Ohio Rate Stabilization Plan, the deadline for achieving structural separation by transferring the ownership of applicable EUOC generating assets to a competitive affiliate was extended until twelve months after the termination of the Rate Stabilization Plan, unless otherwise extended further by the PUCO, or until December 31, 2008, whichever is earlier. All of the EUOC power supply requirements for the Ohio Companies and Penn are provided by FES.

FirstEnergy acquired international assets through its merger with GPU in November 2001. GPU Capital and its subsidiaries provided electric distribution services in foreign countries (see Results of Operations Discontinued Operations). GPU Power and its subsidiaries owned and operated generation facilities in foreign countries. As of January 30, 2004, substantially all of the international operations had been divested (see Note 5) reflecting FirstEnergy s commitment to focus on its core electric business.

FirstEnergy s current focus includes: (1) continuing safe operations; (2) enhancing customer service; (3) optimizing its generation portfolio; (4) minimizing unplanned extended generation outages; (5) effectively managing commodity supplies and risks; (6) reducing its cost structure; (7) enhancing its credit profile and financial flexibility; and (8) managing the skills and diversity of its workforce.

RECLASSIFICATIONS

As further discussed in Notes 1 and 8 to the Consolidated Financial Statements, amounts for purchased power, other operating costs and provisions for depreciation and amortization in FirstEnergy s 2003 Consolidated Statements of Income were reclassified to conform with the current year presentation of generation commodity costs. These reclassifications did not change previously reported results in 2003. Business segment reporting in 2003 was reclassified to conform with the current year business organizations and operations (see Note 8). In addition, as discussed in Note 2 to the Consolidated Financial Statements, reporting of discontinued operations also resulted in the reclassification of revenues, expenses and taxes and certain revenues and expenses have been reclassified and presented on a net basis to conform with the current year presentation.

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RESULTS OF OPERATIONS

The increase in net income of $146 million in the third quarter and $364 million in the first nine months of 2004 reflects higher income from continuing operations of $147 million and $400 million, respectively, when current period results are compared to those of 2003. A significant portion of the third quarter and year-to-date improvement resulted from the absence of a goodwill impairment charge recognized in 2003, lower energy delivery and nuclear production costs and reduced interest expense. These positive factors were offset in part by the impact of mild summer weather and losses recognized on the sale of securities and impairment of several partnership investments. A significant portion of the improvement in the first nine months of 2004 was the absence of a $172 million charge incurred in 2003 for costs disallowed in the JCP&L rate case decision of July 2003. The first nine months of 2003 also included an after-tax charge of $67 million resulting from the abandonment of FirstEnergy s shares in Emdersa s parent company, GPU Argentina Holdings, Inc. and an after-tax credit of $102 million resulting from the cumulative effect of an accounting change due to the adoption of SFAS 143.

The results for the three and nine months ended September 30, 2004 and 2003 are summarized in the table below.

	Three Months Ended September 30,		Nine Months Ended September 30,	
FirstEnergy	**2004**	**2003**	**2004**	**2003**
	(In millions)			
Total revenues	$3,536	$3,423	$9,869	$9,497
Income before discontinued operations and cumulative effect of accounting change	299	152	677	276
Discontinued operations		1		(65)
Cumulative effect of accounting change				102
Net Income	$ 299	$ 153	$ 677	$ 313
Basic Earnings Per Share:				
Income before discontinued operations and cumulative effect of accounting change	$ 0.91	$ 0.51	$ 2.07	$ 0.93
Discontinued operations				(0.22)
Cumulative effect of accounting change				0.35
Net Income	$ 0.91	$ 0.51	$ 2.07	$ 1.06
Diluted Earnings Per Share:				
Income before discontinued operations and cumulative effect of accounting change	$ 0.91	$ 0.50	$ 2.06	$ 0.93
Discontinued operations				(0.22)

Cumulative effect of accounting change				0.34
Net Income	$ 0.91	$ 0.50	$ 2.06	$ 1.05

Results of Operations   Third Quarter of 2004 Compared with the Third Quarter of 2003

Total revenues increased $113 million in the third quarter of 2004. The sources of changes in total revenues are summarized in the following table:

Sources of Revenue Changes	Three Months Ended September 30, 2004	2003	Increase (Decrease)
	(In millions)		
Retail Electric Sales:			
EUOC-Wires	$1,308	$1,360	$ (52)
-Generation	909	920	(11)
FES	161	173	(12)
Wholesale Electric Sales:			
EUOC	137	127	10
FES	515	383	132
Total Electric Sales	3,030	2,963	67
Transmission Revenues:			
Regulated services	81	10	71
Competitive services	20	16	4
Gas Sales	101	111	(10)
Other Revenues:			
EUOC	92	108	(16)
FES	212	197	15
International		8	(8)
Miscellaneous		10	(10)
Total Revenues	$3,536	$3,423	$ 113

Changes in electric generation kilowatt-hour sales and distribution deliveries in the third quarter of 2004 are summarized in the following table:

Changes in KWH Sales	Increase (Decrease)
Electric Generation Sales:	
Retail -	
EUOC	(1.7)%
FES	(5.9)%
Wholesale	20.4%
Total Electric Generation Sales	5.0%
EUOC Distribution Deliveries:	
Residential	(2.1)%
Commercial	1.1%
Industrial	0.4%
Total Distribution Deliveries	(0.3)%

Retail sales by FirstEnergy s EUOC remain the largest source of revenues, contributing more than 70% of electric revenues and over 60% of total revenues. The following major factors contributed to the $63 million decrease in retail electric revenues from FirstEnergy s EUOC in the third quarter of 2004.

Sources of the Changes in EUOC Retail Electric Revenue

Increase (Decrease)	(In millions)
Changes in Customer Consumption:	
Alternative suppliers	$ (10)
Economic, weather and other	(20)
	(30)
Changes in Price:	
Rate changes	25
Shopping incentives	(14)

Rate mix and other	(44)
	(33)
Net Decrease	$ (63)

Reduced customer usage and lower rates contributed to a $63 million decrease ($52 million of distribution deliveries and $11 million of generation) in EUOC retail electric revenues in the third quarter of 2004, compared to the third quarter of 2003. Lower usage due to cooler weather and alternative energy suppliers providing a larger portion of franchise customer energy requirements more than offset the effects of a stronger economy on demand. Alternative energy suppliers provided 24.0% of the total energy delivered to retail customers in the third quarter of 2004, compared to 22.9% in the same period of 2003. Lower prices resulted from two factors a shopping credit rate increase in Ohio and a change in the mix of sales with a smaller proportion of residential distribution deliveries (relative to commercial and industrial deliveries) and fewer retail customers receiving generation in Ohio. Partially offsetting the lower rates due to the changing mix of sales primarily in Ohio were increased rates at JCP&L resulting from higher energy, MTC and SBC rates; the increases in energy rates and MTC are concentrated in the summer billing months. The increase in JCP&L energy, MTC and SBC rates were moderated by lower base distribution rates due to the July 25, 2003, NJBPU base electric rate proceeding decision (see Regulatory Matters New Jersey) effective August 1, 2003.

Electric sales by FES increased by $120 million from additional sales to the wholesale market which increased $132 million in the third quarter of 2004. Higher electric sales to the wholesale market resulted in part from nuclear generation increasing 45% (fossil generation decreased 8%), primarily as a result of the Davis-Besse restart and fewer outages in 2004, which increased total available generation by 8%.

FirstEnergy s regulated and unregulated subsidiaries record purchase and sales transactions with PJM on a gross basis in accordance with EITF 99-19. This gross basis classification of revenues and costs may not be comparable to other energy companies that operate in regions that have not established ISOs and do not meet EITF 99-19 criteria. The aggregate purchase and sales transactions for the three months ended September 30, 2004 and 2003 are summarized as follows:

	Three Months Ended September 30,	
	2004	2003 [(1)]
	(In millions)	
Sales	$366	$264
Purchases	331	269

(1) Certain prior year energy sales and purchases amounts have been reclassified to transmission revenues and expenses (see Note 8).

FirstEnergy s revenues on the Consolidated Statements of Income include wholesale electricity sales revenues from PJM from power sales (as reflected in the table above) during periods when it had additional available power. Revenues also include sales by FirstEnergy of power sourced from PJM (reflected as purchases in the table above) during periods when it required additional power to meet FirstEnergy s retail load requirements and, secondarily, to sell to the wholesale market.

Transmission revenues increased $75 million ($29 million net of related expenses), primarily reflecting transactions with MISO, which began operations in December 2003 through the pooling of transmission capacity of Midwestern utilities to provide unbundled, regional transmission services for electric utilities.

Natural gas sales were $3 million lower (excluding the GLEP partnership interest) due to decreased volumes. Lower than anticipated margins and higher administrative costs resulted in FES exiting customer choice markets as contracts expired. FES scaled back its participation in the natural gas wholesale market due to increasing volatility and risk associated with that business.

The generation margin in the third quarter of 2004 improved by $32 million compared to the same period in 2003 and the ratio of generation margin to revenue remained nearly unchanged. Higher electric generation sales resulted principally from the additional sales in the wholesale market. The gas margin increased $5 million despite lower sales volumes due to better unit margins on sales to commercial and industrial customers.

	Three Months Ended September 30,		
Energy Revenue Net of Commodity Costs	**2004**	**2003**	**Increase (Decrease)**
	(In millions)		
Electric generation revenue	$1,721	$1,603	$ 118
Fuel and purchased power	1,285	1,199	86
Generation Margin	436	404	32

Gas revenue[1]	101	104	(3)
Purchased gas	97	105	(8)
Gas Margin	4	(1)	5
Total Commodity Margins	$ 440	$ 403	$ 37

[1] Excludes GLEP partnership interest.

Income before income taxes, discontinued operations and the cumulative effect of an accounting change increased $228 million in the third quarter of 2004. In addition to the impact of improved electric and gas margins discussed above, the following factors contributed to the increase in income before taxes:

Lower energy delivery expenses of $71 million reflecting the absence in 2004 of significant storm restoration work and the level of distribution reliability costs incurred in the third quarter of 2003 and a higher level of construction activities in 2004 compared to more maintenance activities last year;

Lower nuclear production costs of $31 million primarily as a result of no nuclear refueling outages in the third quarter of 2004 compared to a refueling outage at Beaver Valley Unit 2 ($28 million) during last year s third quarter, and reduced incremental maintenance costs at the Davis-Besse Plant ($16 million) related to its restart;

Lower interest expense of $49 million due to debt and preferred stock redemptions and refinancing activities and other financing activities; and

Absence of the $117 million goodwill impairment charge recognized in the third quarter of 2003.

Partially offsetting the above sources of improved earnings were two factors:

Reduced revenues of $52 million from distribution deliveries due to reduced rates and consumption; and

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A $28 million charge resulting from an impairment of equity interests in several partnerships ($10 million) and losses recognized on the sale of securities ($18 million).

Discontinued Operations

Net income in the third quarter of 2003 included $1 million of after-tax earnings reflecting reclassification of revenues and expenses associated with discontinued operations of FirstEnergy s Bolivia business and FSG subsidiaries - Colonial Mechanical, Webb Technologies and Ancoma, Inc.

Postretirement Plans

Strengthened equity markets, amendments to FirstEnergy s health care benefits plan in the first quarter of 2004 and the Medicare Act signed by President Bush in December 2003 combined to reduce pension and other postemployment benefits costs. Combined, these employee benefit expenses decreased by $29 million in the third quarter of 2004. The following table summarizes the net pension and OPEB expense for the three months ended September 30, 2004 and 2003.

Postretirement Benefits Expense[1]	Three Months Ended September 30,	
	2004	2003
	(In millions)	
Pension	$21	$33
OPEB	22	39
Total	$43	$72

[1] Excludes the capitalized portion of postretirement benefits costs (see Note 4 for total costs).

The decrease in pension and OPEB expenses are included in various cost categories and have contributed to other cost reductions discussed above. See Critical Accounting Policies Pension and Other Postretirement Benefits Accounting for a discussion of the impact of underlying assumptions on postretirement benefits expenses.

Results of Operations First Nine Months of 2004 Compared with the First Nine Months of 2003

Total revenues increased $372 million in the first nine months of 2004. The sources of changes in total revenues are summarized in the following table:

Sources of Revenue Changes	Nine Months Ended September 30, 2004	2003	Increase (Decrease)

		(In millions)	
Retail Electric Sales:			
EUOC-Wires	$3,585	$3,700	$(115)
-Generation	2,440	2,450	(10)
FES	496	416	80
Wholesale Electric Sales:			
EUOC	387	469	(82)
FES	1,422	926	496
Total Electric Sales	8,330	7,961	369
Transmission Revenues:			
EUOC	211	20	191
FES	57	36	21
Gas Sales	380	485	(105)
Other Revenues:			
EUOC	251	286	(35)
FES	627	659	(32)
International		22	(22)
Miscellaneous	13	28	(15)
Total Revenues	$9,869	$9,497	$ 372

Changes in electric generation kilowatt-hour sales and distribution deliveries in the first nine months of 2004 are summarized in the following table:

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Changes in KWH Sales	Increase (Decrease)
Electric Generation Sales:	
Retail -	
EUOC	(3.0)%
FES	9.1%
Wholesale	25.1%
Total Electric Generation Sales	6.8%
EUOC Distribution Deliveries:	
Residential	0.9%
Commercial	2.0%
Industrial	0.8%
Total Distribution Deliveries	1.2%

The following major factors contributed to the $125 million reduction in retail electric revenues from FirstEnergy s EUOC in the first nine months of 2004.

Sources of the Changes in EUOC Retail Electric Revenue Increase (Decrease)	(In millions)
Changes in Customer Consumption:	
Alternative suppliers	$(88)
Economic, weather and other	46
	(42)
Changes in Price:	

Rate changes	(16)
Shopping incentives	(40)
Rate mix and other	(27)
	(83)
Net Decrease	$(125)

Reductions in both customer usage and prices contributed to lower EUOC retail electric revenues. Customers shopping in FirstEnergy s franchise areas for alternative energy suppliers remained the largest single factor reducing usage. Alternative suppliers provided 24.3% of the total energy delivered to retail customers in the first nine months of 2004, compared to 21.1% in the same period of 2003. A stronger economy only partially offset the combined effects of mild summer weather in the third quarter of 2004, compared to the same period of 2003, and reduced usage due to alternative energy suppliers providing a larger portion of franchise customer energy requirements. Lower prices resulted from three factors a shopping credit rate increase in Ohio, a change in the mix of sales with fewer retail customers receiving generation in Ohio, and lower base distribution rates at JCP&L. Partially offsetting JCP&L s lower base distribution rates were higher energy, MTC and SBC rates; the increases in energy rates and MTC are concentrated in the summer billing months. EUOC sales to wholesale customers decreased by $82 million on a 20% reduction in kilowatt-hour sales JCP&L s sales represented substantially all of the decrease.

Electric sales by FES increased by $576 million primarily from additional spot sales in the wholesale market which increased $496 million for the first nine months of 2004. Higher electric sales to the wholesale market were possible due in part to a net 13% increase in generation, which was available from the combination of an increase in FirstEnergy s nuclear generating plants (48% increase) offset in part by lower fossil generation (2% decrease). Retail sales increased by $80 million, primarily from customers within FirstEnergy s Ohio franchise areas switching to FES under Ohio s electricity choice program.

FirstEnergy s regulated and unregulated subsidiaries record purchase and sales transactions with PJM on a gross basis in accordance with EITF 99-19. This gross basis classification of revenues and costs may not be comparable to other energy companies that operate in regions that have not established ISOs and do not meet EITF 99-19 criteria. The aggregate purchase and sales transactions for the nine months ended September 30, 2004 and 2003 are summarized as follows:

	Nine Months Ended September 30,	
	2004	2003 [1]
	(In millions)	
Sales	$1,114	$794
Purchases	980	833

[1] Certain prior year energy sales and purchases amounts have been reclassified to transmission revenues and expenses (see Note 8).

FirstEnergy s revenues on the Consolidated Statements of Income include wholesale electricity sales revenues from PJM from power sales (as reflected in the table above) during periods when it had additional available power. Revenues also include sales by FirstEnergy of power sourced from PJM (reflected as purchases in the table above) during periods when it required additional power to meet FirstEnergy s retail load requirements and, secondarily, to sell to the wholesale market.

Transmission revenues increased $212 million ($66 million net of related expenses), primarily reflecting transactions with MISO, which began operations in December 2003 through the pooling of transmission capacity of Midwestern utilities to provide unbundled regional transmission services for electric utilities.

Natural gas sales decreased $99 million (excluding the GLEP partnership interest) primarily due to the expiration of FES customer choice contracts and reduced sales to the wholesale market. Lower than anticipated margins and higher administrative costs resulted in FES exiting customer choice markets as contracts expired. FES scaled back its participation in the natural gas wholesale market due to increasing volatility and risk associated with that business. Lower sales to large commercial and industrial customers in the first nine months of 2004, compared to the same period in 2003, primarily reflected fewer customers.

The generation margin in the first nine months of 2004 improved by $307 million compared to the same period in 2003 as electric generation revenues increased faster than the related costs for fuel and purchased power. Excluding the impact of the July 2003 JCP&L rate decision discussed above, the generation margin increased $154 million and the ratio of generation margin to revenue improved from 25.3% to 25.9%, reflecting additional lower-cost nuclear generation. Higher electric generation sales resulted principally from the additional sales to the wholesale market. The gas margin increased $2 million from reduced costs.

	Nine Months Ended September 30,		
Energy Revenue Net of Commodity Costs	**2004**	**2003**	**Increase (Decrease)**
	(In millions)		
Electric generation revenue	$4,745	$4,261	$ 484
Fuel and purchased power	3,515	3,338	177

Generation Margin	1,230	923	307
Gas revenue[1]	368	467	(99)
Purchased gas	353	454	(101)
Gas Margin	15	13	2
Total Commodity Margins	$1,245	$ 936	$ 309

(1) Excludes GLEP partnership interest.

Income before income taxes, discontinued operations and the cumulative effect of an accounting change increased $662 million in the first nine months of 2004. In addition to the impact of improved electric and gas margins discussed above, the following factors contributed to the increase in income before taxes:

Lower energy delivery expenses of $58 million reflecting the absence in 2004 of significant storm restoration work and the level of distribution reliability costs incurred in the third quarter of 2003 and a higher level of construction activities in 2004 compared to more maintenance activities last year;

Lower nuclear production costs of $181 million primarily as a result of no nuclear refueling outages in the first nine months of 2004 compared to refueling outages at Beaver Valley Unit 1 ($47 million), Beaver Valley Unit 2 ($28 million) and the Perry Plant ($41 million) during the same period last year and reduced incremental maintenance costs at the Davis-Besse Plant ($70 million) related to its restart;

A net $58 million decrease in employee benefits expenses primarily as a result of reduced postretirement benefit plan expenses (see Postretirement Plans below), offset in part by additional severance costs;

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Absence of the $117 million goodwill impairment charge recognized in the third quarter of 2003; and

Lower interest expense of $109 million due to debt and preferred stock redemptions and refinancing activities.

Partially offsetting the above sources of improved earnings were three factors:

Reduced revenues of $115 million from distribution deliveries due to reduced rates and consumption;

Charges for depreciation and amortization that increased by $35 million due to an increase in amortization of regulatory assets (offset in part by reduced depreciation rates resulting from the JCP&L rate case); and

A $28 million charge resulting from an impairment of equity interests in several partnerships ($10 million) and losses recognized on the sale of securities ($18 million).

Discontinued Operations

Net income in the first nine months of 2003 included after-tax losses from discontinued operations of $65 million reflecting the reclassification of revenues and expenses associated with divestitures of FirstEnergy s Argentina and Bolivia businesses, FSG subsidiaries (Colonial Mechanical, Webb Technologies and Ancoma, Inc.) and NEO.

Cumulative Effect of Accounting Change

Results in the first nine months of 2003 included an after-tax credit to net income of $102 million recorded upon the adoption of SFAS 143 in January 2003. FirstEnergy identified applicable legal obligations as defined under the new standard for nuclear power plant decommissioning and reclamation of a sludge disposal pond at the Bruce Mansfield Plant. As a result of adopting SFAS 143 in January 2003, asset retirement costs of $602 million were recorded as part of the carrying amount of the related long-lived asset, offset by accumulated depreciation of $415 million. The ARO liability at the date of adoption was $1.11 billion, including accumulated accretion for the period from the date the liability was incurred to the date of adoption. As of December 31, 2002, FirstEnergy had recorded decommissioning liabilities of $1.24 billion. FirstEnergy expects substantially all of its nuclear decommissioning costs for Met-Ed, Penelec, JCP&L and Penn to be recoverable in rates over time. Therefore, FirstEnergy recognized a regulatory liability of $185 million upon adoption of SFAS 143 for the transition amounts related to establishing the ARO for nuclear decommissioning for those companies. The remaining cumulative effect adjustment for unrecognized depreciation and accretion offset by the reduction in the liabilities and the reversal of accumulated estimated removal costs for non-regulated generation assets, was a $175 million increase to income, or $102 million net of income taxes.

Postretirement Plans

Strengthened equity markets in 2003, amendments to FirstEnergy s health care benefits plan in the first quarter of 2004 and the Medicare Act signed by President Bush in December 2003 combined to reduce pension and other postemployment benefits costs. Combined, these employee benefit expenses decreased by $77 million in the first nine months of 2004. The following table summarizes the net pension and OPEB expense for the nine months ended September 30, 2004 and 2003.

	Nine Months Ended September 30,	
Postretirement Benefits Expense(1)	**2004**	**2003**

	(In millions)	
Pension	$ 64	$ 91
OPEB	68	118
Total	$132	$209

(1) Excludes the capitalized portion of postretirement benefits costs (see Note 4 for total costs).

The decrease in pension and OPEB expenses are included in various cost categories and have contributed to other cost reductions discussed above. See Critical Accounting Policies Pension and Other Postretirement Benefits Accounting for a discussion of the impact of underlying assumptions on postretirement benefits expenses.

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RESULTS OF OPERATIONS   BUSINESS SEGMENTS

FirstEnergy manages its business as two separate major business segments   regulated services and competitive services. In the first quarter of 2004, management made certain changes in presenting results for these two segments (see Note 8). The regulated services segment no longer includes a portion of generation services. The regulated services segment designs, constructs, operates and maintains FirstEnergy s regulated transmission and distribution systems. Its revenues are primarily derived from the delivery of electricity and transition cost recovery. All generation services are now reported in the competitive services segment. That segment s revenues include all generation electric sales revenues (including the generation services to regulated franchise customers who have not chosen an alternative generation supplier) and all domestic unregulated energy and energy-related services including commodity sales (both electricity and natural gas) in the retail and wholesale markets, marketing, generation, commodity sourcing and other competitive energy-application services such as heating, ventilation and air-conditioning.   Other   consists of interest expense related to holding company debt, corporate support services and the international businesses that were substantially divested by the first quarter of 2004. FirstEnergy s two major business segments include all or a portion of the following business entities:

The regulated services segment includes the regulated delivery of electricity including transmission and distribution services by its eight electric utility operating companies in Ohio, Pennsylvania and New Jersey (OE, CEI, TE, Penn, JCP&L, Met-Ed, Penelec and ATSI); and

The competitive services business segment consists of the subsidiaries (FES, FSG, MYR and FirstCom) that principally operate unregulated energy and energy-related businesses, including the operation of FirstEnergy s generation facilities as a result of the deregulation of the Companies   electric generation business (see Note 6 Regulatory Matters).

Financial results discussed below include revenues and expenses from transactions among FirstEnergy s business segments. A reconciliation of segment financial results to consolidated financial results is provided in Note 8 to the consolidated financial statements. Net income (loss) by business segment was as follows:

Net Income (Loss)	Three Months Ended September 30,		Nine Months Ended September 30,	
By Business Segment	**2004**	**2003**	**2004**	**2003**
		(In millions)		
Regulated services	$315	$293	$ 760	$ 856
Competitive services	47	(86)	99	(324)
Other[(1)]	(63)	(54)	(182)	(219)
Total	$299	$153	$ 677	$ 313

(1) Includes international operations and reflects an after-tax charge of $67 million in the nine months ended September 30, 2003 related to the abandonment of FirstEnergy s Argentina Business operations.

Regulated Services   Third Quarter of 2004 Compared with the Third Quarter of 2003

Financial results for the regulated services segment were as follows:

Regulated Services	**Three Months Ended September 30, 2004**	**2003**	**Increase**
	(In millions)		
Total revenues	$1,480	$1,478	$ 2
Net income	315	293	22

The change in operating revenues resulted from the following sources:

Sources of Revenue Changes	**Three Months Ended September 30, 2004**	**2003**	**Increase (Decrease)**
	(In millions)		
Electric sales	$1,308	$1,360	$(52)
Other revenues	172	118	54
Total Revenues	$1,480	$1,478	$ 2

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The net increase in operating revenues resulted from:

- A decrease of $52 million in retail sales a $37 million reduction in revenues from distribution deliveries (wires and transition revenue) and a $15 million increase in the credits for shopping incentives to customers; and

- A net $54 million increase in other revenues due to higher transmission revenues.

Income before discontinued operations and the cumulative effect of an accounting change increased $22 million in the third quarter of 2004 and pre-tax income increased by $34 million from the following factors:

- Lower energy delivery expenses of $71 million reflecting the absence in 2004 of significant storm restoration work and the level of distribution reliability costs incurred in the third quarter of 2003 and a higher level of construction activities in 2004 compared to more maintenance activities last year;

- A net margin increase from transmission-related transactions of $30 million; and

- Lower interest expense of $30 million due to debt and preferred stock redemptions and refinancing activities.

Partially offsetting the above sources of improved earnings were several factors:

- Reduced revenues of $52 million from distribution deliveries resulting from reduced electricity deliveries and lower prices;

- An increase of $9 million in ancillary transmission service refund expenses;

- Decreases in other revenues of $10 million reflecting the absence of income from certificates of deposit redeemed in June 2004 and lower JCP&L Transition TBC revenues; and

- Charges for depreciation and amortization that increased $5 million due to additional amortization of regulatory assets (offset in part by reduced depreciation rates resulting from the JCP&L rate case).

Competitive Services Third Quarter of 2004 Compared with the Third Quarter of 2003

Financial results for the competitive services segment were as follows:

	Three Months Ended September 30,		
Competitive Services	**2004**	**2003**	**Increase**
		(In millions)	
Total revenues	$2,064	$1,929	$ 135
Income (loss) before discontinued operations	47	(88)	135
Net income (loss)	47	(86)	133

The change in total revenues resulted from the following sources:

Sources of Revenue Changes	Three Months Ended September 30, 2004	2003	Increase (Decrease)
	(In millions)		
Electric sales	$1,722	$1,603	$ 119
Natural gas sales	101	111	(10)
Energy-related sales	211	205	6
Other revenues	30	10	20
Total Revenues	$2,064	$1,929	$ 135

The net increase in electric sales resulted from:

Increased FES wholesale revenues of $132 million (primarily spot sales) and higher EUOC sales to wholesale customers of $10 million; and

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Lower retail generation sales through customer choice programs ($12 million) and decreased generation sales to the EUOC ($11 million).

Natural gas sales were $10 million lower primarily due to the sale of GLEP in June 2004. Excluding FirstEnergy s interest in GLEP from 2003 results, natural gas sales were $3 million lower due to decreased volumes. Lower than anticipated margins and higher administrative costs resulted in FES exiting customer choice markets as contracts expired. FES scaled back its participation in the wholesale market due to increasing volatility and risk associated with that business.

The generation margin increased $32 million. Higher electric generation revenues resulted from additional sales to the wholesale market which were possible due to increased nuclear generation. The margin on gas sales increased $5 million despite lower sales volumes due to better unit margins on sales to commercial and industrial customers using lower supply costs previously dedicated to the customer choice contracts.

Income before discontinued operations and the cumulative effect of an accounting change increased $135 million in the third quarter of 2004 and pre-tax income increased by $211 million. In addition to the effect of improved electric and gas margins discussed above, the following factors contributed to the increase in pre-tax income:

Lower nuclear production costs of $31 million primarily as a result of no nuclear refueling outages in the third quarter of 2004 compared to a refueling outage at Beaver Valley Unit 2 ($28 million) during last year s third quarter, and reduced incremental maintenance costs at the Davis-Besse Plant ($16 million) related to its restart;

Absence of the $117 million goodwill impairment charge recognized in the third quarter of 2003; and

Reduced employee benefits expenses primarily as a result of lower postretirement benefit plan expenses (see Postretirement Plans above).

Regulated Services First Nine Months of 2004 Compared with the First Nine Months of 2003

Financial results for the regulated services segment were as follows:

	Nine Months Ended September 30,		
Regulated Services	**2004**	**2003**	**Increase (Decrease)**
		(In millions)	
Total revenues	$4,047	$4,005	$ 42
Income before cumulative effect of accounting change	760	754	6
Net income	760	856	(96)

The change in operating revenues resulted from the following sources:

Nine Months Ended September 30,

Sources of Revenue Changes	2004	2003	Increase (Decrease)
		(In millions)	
Electric sales	$3,585	$3,700	$(115)
Other revenues	462	305	157
Total Revenues	$4,047	$4,005	$ 42

The increase in operating revenues resulted from:

A net decrease of $115 million in retail sales a $94 million decrease in revenues from distribution deliveries and a $21 million increase in shopping incentive credits to customers; and

A net $157 million increase in other revenues primarily due to higher transmission revenues.

Income before discontinued operations and the cumulative effect of an accounting change increased $6 million in the first nine months of 2004 and pre-tax income decreased by $5 million. The following factors contributed to the changes:

Lower energy delivery expense of $58 million reflecting the absence in 2004 of significant storm restoration work and the level of distribution reliability costs incurred in the third quarter of 2003 and a higher level of construction activities in 2004 compared to more maintenance activities last year;

A net contribution from transmission-related transactions of $54 million; and

Lower interest expense of $70 million due to debt and preferred stock redemptions and refinancing activities.

Partially offsetting the above sources of improved earnings were two factors:

Reduced revenues of $115 million from lower distribution deliveries and prices; and

Increased charges for depreciation and amortization of $30 million due to an increase in amortization of regulatory assets offset in part by reduced depreciation rates resulting from the JCP&L rate case.

Competitive Services First Nine Months of 2004 Compared with the First Nine Months of 2003

Financial results for the competitive services segment were as follows:

	Nine Months Ended September 30,		
Competitive Services	**2004**	**2003**	**Increase**
		(In millions)	
Total revenues	$5,808	$5,412	$ 396
Income (loss) before discontinued operations and cumulative effect of accounting change	99	(321)	420
Net income (loss)	99	(324)	423

The change in total revenues resulted from the following sources:

	Nine Months Ended September 30,		
Sources of Revenue Changes	**2004**	**2003**	**Increase (Decrease)**
		(In millions)	
Electric sales	$4,745	$4,261	$ 484
Natural gas sales	380	485	(105)
Energy-related sales	601	612	(11)
Other revenues	82	54	28
Total Revenues	$5,808	$5,412	$ 396

The increase in electric revenues resulted from:

- Higher retail generation sales from customer choice programs ($80 million) offset in part by lower generation sales of the EUOC ($10 million); and

- Increased wholesale revenues of $496 million from FES (primarily spot sales) offset in part by an $82 million decrease in EUOC sales to wholesale customers.

Natural gas sales decreased $105 million primarily due to the expiration of FES customer choice contracts and reduced sales to the wholesale market. Lower than anticipated margins and higher administrative costs resulted in FES exiting customer choice markets as contracts expired. Due to increased volatility and perceived risk, FES reduced its participation in the wholesale market. Decreased sales to large commercial and industrial customers in the first nine months of 2004 primarily reflected fewer customers.

The generation margin increased $307 million as electric generation revenues increased at a greater rate than the related costs for fuel and purchased power. Higher electric generation revenues resulted from additional sales to the wholesale market. Excluding the impact of the July 2003 JCP&L rate decision, as discussed above, the generation margin increased $154 million. The margin on gas sales increased $2 million on reduced sales.

Income before discontinued operations and the cumulative effect of an accounting change increased $420 million in the first nine months of 2004. In addition to the effect of improved generation and gas margins discussed above, the following factors contributed to that increase:

Lower nuclear production costs of $181 million primarily as a result of no nuclear refueling outages in the first nine months of 2004 compared to refueling outages at Beaver Valley Unit 1 ($47 million), Beaver Valley Unit 2 ($28 million) and the Perry Plant ($41 million) during the same period last year and reduced incremental maintenance costs at the Davis-Besse Plant ($70 million) related to its restart;

Absence of the $117 million goodwill impairment charge recognized in the third quarter of 2003; and

Reduced employee benefits expenses primarily as a result of lower postretirement benefit plan expenses (see Postretirement Plans above).

CAPITAL RESOURCES AND LIQUIDITY

FirstEnergy s cash requirements in 2004 for operating expenses, construction expenditures, scheduled debt maturities and preferred stock redemptions are expected to be met without increasing FirstEnergy s net debt and preferred stock outstanding. Available borrowing capacity under short-term credit facilities will be used to manage working capital requirements. Over the next two years, FirstEnergy expects to meet its contractual obligations with cash from operations. Thereafter, FirstEnergy expects to use a combination of cash from operations and funds from the capital markets.

Changes in Cash Position

The primary source of ongoing cash for FirstEnergy, as a holding company, is cash dividends from its subsidiaries. The holding company also has access to $1.375 billion of revolving credit facilities, ($1.214 billion unused as of September 30, 2004). In the first nine months of 2004, FirstEnergy received $515 million of cash dividends from its subsidiaries and paid $368 million in cash common stock dividends to its shareholders. There are no material restrictions on the issuance of cash dividends by FirstEnergy s subsidiaries. As of September 30, 2004, FirstEnergy had $68 million of cash and cash equivalents, compared with $114 million as of December 31, 2003. The major source of changes in these balances are summarized below.

Cash Flows From Operating Activities

FirstEnergy s consolidated net cash from operating activities is provided by its regulated and competitive energy services businesses (see Results of Operations Business Segments above). Net cash provided from operating activities in the third quarter and first nine months of 2004, compared with the corresponding periods of 2003, were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Operating Cash Flows	**2004**	**2003**	**2004**	**2003**
		(In millions)		
Cash earnings [1]	$ 745	$596	$1,634	$1,271
Pension trust contribution	(500)		(500)	
Working capital and other	320	283	401	34
Total	$ 565	$879	$1,535	$1,305

(1) Includes net income, depreciation and amortization, deferred income taxes, investment tax credits and major noncash charges.

Net cash provided from operating activities decreased $314 million in the third quarter of 2004 compared to the same period last year due to a voluntary pension trust contribution of $500 million in the third quarter of 2004. The decrease was partially offset by a $149 million of increased cash earnings, as described above under Results of Operations. During the first nine months of 2004, net cash provided from operating activities increased $230 million. The increase in the first nine months of 2004 was due to a $367 million increase from changes in working capital and $363 million of higher cash earnings, partially offset by the $500 million pension trust contribution. The working capital change primarily resulted from a $144 million decrease in receivables (including the net proceeds from the settlement of FirstEnergy s claim against NRG, Inc. for the terminated sale of four power plants) and a $90 million increase in accrued tax balances.

Cash Flows From Financing Activities

The following table provides details regarding security issuances and redemptions during the third quarter and first nine months of 2004 and 2003:

Securities Issued or Redeemed	Three Months Ended September 30, 2004	Three Months Ended September 30, 2003	Nine Months Ended September 30, 2004	Nine Months Ended September 30, 2003
	(In millions)			
New Issues				
Common stock	$	$ 935	$	$ 935
Pollution control notes	77		261	
Senior secured notes			550	400
Long term revolving credit	10			40
Unsecured notes			150	331
	$ 87	$ 935	$ 961	$1,706
Redemptions				
First mortgage bonds	$206	$ 302	$ 588	$1,002
Pollution control notes	80	4	80	54
Senior secured notes	374	23	447	282
Long-term revolving credit		240	300	
Unsecured notes	112		337	
Preferred stock	1	1	1	126
	$773	$ 570	$1,753	$1,464
Short-term Borrowings, Net	$228	$(799)	$ (219)	$ (847)

Net cash used for financing activities increased by $54 million in the third quarter of 2004 from the third quarter of 2003. The increase in cash used for financing activities resulted primarily from an increase in net redemptions and refinancings of debt and preferred securities and higher dividend payments. Redemption and refinancing activities for debt and preferred stock aggregated approximately $451 million during the third quarter of 2004 (including $25 million of pollution control note repricings). The redemption and refinancing activities and pollution control note repricings are expected to result in annualized savings of $47 million. Net cash used for the above financing activities increased by $512 million in the first nine months of 2004 from the same period of 2003. The increase in cash used for financing activities resulted primarily from the absence of equity financing in 2004 and higher dividend payments offset in part by the net issuance of debt.

FirstEnergy has sinking fund requirements for preferred stock and maturing long-term debt during the remainder of 2004, aggregating $23 million. These cash requirements are expected to be satisfied from internal cash.

FirstEnergy had approximately $303 million of short-term indebtedness as of September 30, 2004 compared to approximately $522 million as of December 31, 2003. Unused borrowing capability as of September 30, 2004 included the following:

Unused Borrowing Capability	**FirstEnergy Holding Company**	**OE**	**Total**
		(In millions)	
Long-Term Revolving Credit	$1,375	$375	$1,750
Utilized	(10)		(10)
Letters of Credit	(151)		(151)
Net	1,214	375	1,589
Short-Term Bank Facilities		34	34
Utilized		(20)	(20)
Net		14	14
Total Unused Borrowing Capability	$1,214	$389	$1,603

As of September 30, 2004, the Ohio EUOC and Penn had the aggregate capability to issue approximately $4.1 billion of additional FMBs on the basis of property additions and retired bonds under the terms of their respective mortgage indentures. The issuances of FMBs by OE and CEI are also subject to provisions of their senior note indentures generally limiting the incurrence of additional secured debt, subject to certain exceptions that would permit, among other things, the issuance of secured debt (including FMBs) (i) supporting pollution control notes or similar obligations, or (ii) as an extension, renewal or replacement of previously outstanding secured debt. In addition, these provisions would permit OE and CEI to incur additional secured debt not otherwise permitted by a specified exception of up to $639 million and $582 million, respectively, as of September 30, 2004. Under the provisions of its senior note indenture, JCP&L may issue additional FMBs only as collateral for senior notes. As of September 30, 2004, JCP&L had the capability to issue $490 million of additional senior notes upon the basis of FM collateral. Based upon applicable earnings coverage tests in their respective charters, OE, TE, Penn, and JCP&L could issue a total of $4.0 billion of preferred stock (assuming no additional debt was issued) as of September 30, 2004. CEI, Met-Ed and Penelec have no restrictions on the issuance of preferred stock.

FirstEnergy s working capital and short-term borrowing needs are met principally with a syndicated $1 billion three-year revolving credit facility maturing in June 2007. Combined with a syndicated $375 million three-year facility for FirstEnergy maturing in October 2006, a $125 million three-year facility for OE maturing in October 2006, and a syndicated $250 million two-year facility for OE maturing in May 2005, FirstEnergy s primary syndicated credit facilities total $1.75 billion. These revolving credit facilities, combined with an aggregate $550 million of accounts receivable financing facilities for OE, CEI, TE, Met-Ed, Penelec and Penn, are intended to provide liquidity to meet the short-term working capital requirements of FirstEnergy and its subsidiaries. Total unused borrowing capability under existing facilities and accounts receivable financing facilities totaled $1.7 billion as of September 30, 2004.

Borrowings under these facilities are conditioned on FirstEnergy and/or OE maintaining compliance with certain financial covenants in the agreements. FirstEnergy and OE are each required to maintain a debt to total capitalization ratio of no more than 0.65 to 1 and a contractually-defined fixed charge coverage ratio of no less than 2 to 1. FirstEnergy and OE are in compliance with these financial covenants. As of September 30, 2004, FirstEnergy s and OE s fixed charge coverage ratios, as defined under the credit agreements, were 4.08 to 1 and 7.36 to 1, respectively. FirstEnergy s and OE s debt to total capitalization ratios, as defined under the credit agreements, were 0.55 to 1 and 0.39 to 1, respectively. The ability to draw on each of these facilities is also conditioned upon FirstEnergy or OE making certain representations and warranties to the lending banks prior to drawing on their respective facilities, including a representation that there has been no material adverse change in their business, their condition (financial or otherwise), their results of operations, or their prospects.

FirstEnergy s and OE s primary credit facilities contain no provisions restricting their ability to borrow, or accelerating repayment of outstanding loans, as a result of any change in their S&P or Moody s credit ratings. The primary facilities do contain pricing grids , whereby the cost of funds borrowed under the facilities is related to the credit ratings of the company borrowing the funds.

FirstEnergy s regulated companies have the ability to borrow from each other and FirstEnergy to meet their short-term working capital requirements. A similar but separate arrangement exists among its competitive companies. FESC administers these two money pools and tracks surplus funds of FirstEnergy and the respective regulated and competitive subsidiaries, as well as proceeds available from bank borrowings. For the regulated companies, available bank borrowings include $1.75 billion from FirstEnergy s and OE s revolving credit facilities. For the competitive companies, available bank borrowings include only the $1.375 billion of FirstEnergy s revolving credit facilities. Companies receiving a loan under the money pool agreements must repay the principal amount of such loan, together with accrued interest, within 364 days of borrowing the funds. The rate of interest is the same for each company receiving a loan from their respective pool and is based on the average cost of funds available through the pool. The average interest rate for borrowings in the third quarter of 2004 was 1.28% for the regulated companies pool and 1.32% for the competitive companies pool.

On September 1, 2004, Penelec redeemed at par $100 million principal amount of its subordinated debentures in connection with the concurrent redemption at par of $100 million principal amount of Penelec Capital Trust 7.34% Trust Preferred Securities.

On July 22, 2004, S&P updated its analysis of U.S. utility FMB in response to changes in the industry. As a result of its revised methodology for evaluating default risk, S&P raised its FMB credit ratings for 20 U.S. utility companies including JCP&L and Penn. JCP&L s FMB credit rating was upgraded to BBB+ from BBB and Penn s

FMB credit rating was upgraded to BBB from BBB-.

On August 26, 2004, S&P lowered its rating on certain Met-Ed Senior Notes to BBB- from BBB. The rationale for the ratings change was that Met-Ed s senior secured notes, in aggregate, now comprise greater than 80% of Met-Ed s total debt outstanding. According to the terms of the senior note indenture, once the 80% threshold is reached, the collateral mortgage bond security falls away and all senior secured notes that were secured by Met-Ed s senior note indenture become unsecured. The one notch lower rating reflects this loss of collateral security. The BBB senior secured rating on Met-Ed s first mortgage bonds remain unchanged.

Also on August 26, 2004, S&P stated that a favorable outcome of the Ohio Rate Stabilization Plan auction process and a favorable resolution of pending environmental litigation would support a higher ratings outlook, or possibly a higher rating. S&P noted that a ratings upgrade in 2004 does not appear likely because those major issues would most likely not be resolved before the end of 2004. On September 14, 2004, S&P stated that FirstEnergy s $500 million voluntary contribution to its pension plan was credit neutral.

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Cash Flows From Investing Activities

Net cash flows provided from investing activities totaled $5 million in the third quarter of 2004, compared to net cash flows used of $219 million for investing activities for the same period of 2003. The $224 million change resulted from $278 million in cash proceeds from certificates of deposit in the third quarter of 2004.

The following table summarizes investments by FirstEnergy s regulated services and competitive services segments in the third quarter and first nine months of 2004:

Summary of Cash Used for Investing Activities	**Property Additions**	**Investments**	**Other**	**Total**
Sources (Uses)		**(In millions)**		
Three Months Ended September 30, 2004				
Regulated Services	$(157)	$246(1)	$(68)	$ 21
Competitive Services	(47)	(10)	(2)	(59)
Other	(7)	(33)	83	43
Total	$(211)	$203	$ 13	$ 5
Nine Months Ended September 30, 2004				
Regulated Services	$(377)	$181(1)(2)	$(75)	$(271)
Competitive Services	(152)	188(3)	2	38
Other	(17)	20	64	67
Total	$(546)	$389	$ (9)	$(166)

(1) Includes $278 million in cash proceeds from certificates of deposit.

(2) Includes $51 million refunding payment to a NUG trust fund.

(3) Includes $200 million in cash proceeds from the sale of GLEP.

In the last quarter of 2004, capital requirements for property additions and capital leases are expected to be approximately $293 million, including $75 million for nuclear fuel.

FirstEnergy s current forecast reflects expenditures of approximately $2.3 billion for property additions and improvements from 2004-2006, of which approximately $717 million is applicable to 2004. Investments for additional nuclear fuel during the 2004-2006 period are estimated to be approximately $303 million, of which approximately $90 million applies to 2004. During the same periods, the Companies nuclear fuel investments are expected to be reduced by approximately $269 million and $88 million, respectively, as the nuclear fuel is consumed.

GUARANTEES AND OTHER ASSURANCES

As part of normal business activities, FirstEnergy and the Companies enter into various agreements to provide financial or performance assurances to third parties. Such agreements include contract guarantees, surety bonds, and ratings contingent collateralization provisions.

As of September 30, 2004, the maximum potential future payments under outstanding guarantees and other assurances totaled approximately $2.1 billion as summarized below:

Guarantees and Other Assurances	**Maximum Exposure**
	(In millions)
FirstEnergy Guarantees of Subsidiaries:	
Energy and Energy-Related Contracts [1]	$ 862
Other [2]	149
	1,011
Surety Bonds	280
Letters of Credit [3][4]	815
Total Guarantees and Other Assurances	$2,106

(1) Issued for a one-year term, with a 10-day termination right by FirstEnergy.

(2) Issued for various terms.

(3) Includes letters of credit of $151 million issued for various terms under letter of credit capacity available in FirstEnergy s syndicated revolving credit facilities.

(4) Includes unsecured letters of credit of approximately $216 million pledged in connection with the sale and leaseback of Beaver Valley Unit 2 by CEI and TE, as well as an unsecured letter of credit of $237 million pledged in connection with the sale and leaseback of Beaver Valley Unit 2 by OE and unsecured letters of credit of $211 million pledged in connection with the sale and leaseback of Perry Unit 1 by OE.

FirstEnergy guarantees energy and energy-related payments of its subsidiaries involved in energy marketing activities principally to facilitate normal physical transactions involving electricity, gas, emission allowances and coal. FirstEnergy also provides guarantees to various providers of subsidiary financing principally for the acquisition of property, plant and equipment. These agreements legally obligate FirstEnergy and its subsidiaries to fulfill the obligations of those subsidiaries directly involved in energy and energy-related transactions or financings where the law might otherwise limit the counterparties claims. If demands of a counterparty were to exceed the ability of a subsidiary to satisfy existing obligations, FirstEnergy s guarantee enables the counterparty s legal claim to be satisfied by FirstEnergy s other assets. The likelihood is remote that such parental guarantees will increase amounts otherwise paid by FirstEnergy to meet its obligations incurred in connection with ongoing energy-related activities.

While these types of guarantees are normally parental commitments for the future payment of subsidiary obligations, subsequent to the occurrence of a credit rating downgrade or material adverse event the immediate payment of cash collateral or provision of an LOC may be required. The following table summarizes collateral provisions as of September 30, 2004:

Collateral Provisions	Total Exposure (1)	Collateral Paid: Cash	Collateral Paid: Letters of Credit	Remaining Exposure
		(In millions)		
Rating downgrade	$358	$145	$ 18	$195
Adverse event	113	—	23	90
Total	$471	$145	$ 41	$285

(1) As of October 12, 2004, FirstEnergy s total exposure decreased to $465 million and the remaining exposure decreased to $272 million net of $152 million of cash collateral and $41 million of LOC collateral provided to counterparties.

Most of FirstEnergy s surety bonds are backed by various indemnities common within the insurance industry. Surety bonds and related guarantees provide additional assurance to outside parties that contractual and statutory obligations will be met in a number of areas including construction contracts, environmental commitments and various retail transactions.

Various contracts include credit enhancements in the form of cash collateral, letters of credit or other security in the event of a reduction in credit rating. Requirements of these provisions vary and typically require more than one rating reduction to below investment grade by S&P or Moody s to trigger additional collateralization.

On July 15, 2004, FirstEnergy received $289 million of cash (principal and interest) for maturing OE certificates of deposit. These certificates of deposit related to OE s Beaver Valley Unit 2 sale and leaseback financing. Cash collateralized letters of credit associated with that financing were cancelled and replaced by unsecured LOCs totaling approximately $237 million (as described above) during the second quarter of 2004.

In connection with the sale of the TEBSA project in Colombia in January 2004, FirstEnergy guaranteed the obligations of the operators of the project, up to a maximum of $6 million (subject to escalation) under the project s operation and maintenance agreement for so long as such obligations exist. The purchaser of TEBSA agreed to indemnify FirstEnergy against any loss under this guarantee. Also in connection with the TEBSA project, FirstEnergy has provided the TEBSA project lenders with a $60 million LOC and a $400,000 LOC. The $60 million LOC was established as a substitute asset for FirstEnergy s interest in its Midlands companies pursuant to an indemnity agreement in favor of the TEBSA project lenders. As of October 15, 2004, the value of the LOC decreased to $46 million. The balance will continue to decline annually and will be fully discharged and released in October 2010. The substitute LOC enabled FirstEnergy to sell its remaining 20.1% interest in Avon (parent of Midlands Electricity in the United Kingdom). The $400,000 LOC was established to secure the TEBSA project lenders in the event that liquidated shares of TEBSA were unable to be converted into U.S. currency. The $400,000 LOC will terminate upon the registration of certain of TEBSA s stock with the Colombian Central Bank.

OFF-BALANCE SHEET ARRANGEMENTS

FirstEnergy has obligations that are not included on its Consolidated Balance Sheets related to the sale and leaseback arrangements involving Perry Unit 1, Beaver Valley Unit 2 and the Bruce Mansfield Plant. The present value of these sale and leaseback operating lease commitments, net of trust investments, total $1.4 billion as of September 30, 2004.

CEI and TE sell substantially all of their retail customer receivables to CFC, a wholly owned subsidiary of CEI. CFC subsequently transfers the receivables to a trust (a qualified special purpose entity under SFAS 140) under an asset-backed securitization agreement. This arrangement provided $199 million of off-balance sheet financing as of September 30, 2004.

FirstEnergy has equity ownership interests in various businesses that are accounted for using the equity method. There are no undisclosed material contingencies related to these investments. Certain guarantees that FirstEnergy does not expect to have a material current or future effect on its financial condition, liquidity or results of operations are disclosed under contractual obligations above.

MARKET RISK INFORMATION

FirstEnergy uses various market risk sensitive instruments, including derivative contracts, primarily to manage the risk of price and interest rate fluctuations. FirstEnergy s Risk Policy Committee, comprised of executive officers, exercises an independent risk oversight function to ensure compliance with corporate risk management policies and prudent risk management practices.

Commodity Price Risk

FirstEnergy is exposed to market risk primarily due to fluctuating electricity, natural gas, coal, nuclear fuel and emission allowance prices. To manage the volatility relating to these exposures, it uses a variety of non-derivative and derivative instruments, including forward contracts, options, futures contracts and swaps. The derivatives are used principally for hedging purposes and, to a much lesser extent, for trading purposes. Most of FirstEnergy s non-hedge derivative contracts represent non-trading positions that do not qualify for hedge treatment under SFAS 133.

The change in the fair value of commodity derivative contracts related to energy production during the third quarter and first nine months of 2004 is summarized in the following table:

Increase (Decrease) in the Fair Value
Of Commodity Derivative Contracts

	Three Months Ended September 30, 2004			Nine Months Ended September 30, 2004		
	Non-Hedge	**Hedge**	**Total**	**Non-Hedge**	**Hedge**	**Total**
			(In millions)			
Change in the Fair Value of Commodity Derivative Contracts:						
Outstanding net asset at beginning of period	$62	$ 8	$70	$67	$ 12	$ 79
New contract value when entered						
Additions/change in value of existing contracts		3	3	(5)	11	6
Change in techniques/assumptions						
Settled contracts	1	(4)	(3)	1	(16)	(15)
Outstanding net asset at end of period (1)	63	7	70	63	7	70
Non-commodity Net Assets at End of Period:						
Interest Rate Swaps (2)		27	27		27	27
Net Assets Derivative Contracts at End of Period	$63	$ 34	$97	$63	$ 34	$ 97
Impact of Changes in Commodity Derivative Contracts (3)						
Income Statement Effects (Pre-Tax)	$ 1	$	$ 1	$ (3)	$	$ (3)
Balance Sheet Effects:						
Other Comprehensive Income (Pre-Tax)	$	$ (1)	$ (1)	$	$ (5)	$ (5)
Regulatory Liability	$	$	$	$ (1)	$	$ (1)

(1) Includes $60 million in non-hedge commodity derivative contracts which are offset by a regulatory liability.

(2) Interest rate swaps are treated as fair value hedges. Changes in derivative values are offset by changes in the hedged debts premium or discount.

(3) Represents the increase in value of existing contracts, settled contracts and changes in techniques/assumptions.

Derivatives included on the Consolidated Balance Sheet as of September 30, 2004 were as follows:

Non-Hedge	Hedge	Total
	(In millions)	

Current-			
Other Assets	$ 6	$ 6	$12
Other Liabilities	(4)		(4)
Non-Current-			
Other Deferred Charges	61	31	92
Other Liabilities		(3)	(3)
Net assets	$63	$34	$97

The valuation of derivative contracts is based on observable market information to the extent that such information is available. In cases where such information is not available, FirstEnergy relies on model-based information. The model provides estimates of future regional prices for electricity and an estimate of related price volatility. FirstEnergy uses these results to develop estimates of fair value for financial reporting purposes and for internal management decision making. Sources of information for the valuation of commodity derivative contracts by year are summarized in the following table:

Source of Information Fair Value by Contract Year	**2004[1]**	**2005**	**2006**	**2007**	**Thereafter**	**Total**
			(In millions)			
Prices actively quoted[2]	$ 1	$ 4	$ 1	$	$	$ 6
Other external sources[3]	9	12	10			31
Prices based on models				10	23	33
Total[4]	**$ 10**	**$16**	**$11**	**$10**	**$ 23**	**$70**

(1) For the last quarter of 2004.

(2) Exchange traded.

(3) Broker quote sheets.

(4) Includes $60 million in non-hedge commodity derivative contracts which are offset by a regulatory liability.

FirstEnergy performs sensitivity analyses to estimate its exposure to the market risk of its commodity positions. A hypothetical 10% adverse shift (an increase or decrease depending on the derivative position) in quoted market prices in the near term on both FirstEnergy s trading and nontrading derivative instruments would not have had a material effect on its consolidated financial position (assets, liabilities and equity) or cash flows as of September 30,

2004. Based on derivative contracts held as of September 30, 2004, an adverse 10% change in commodity prices would decrease net income by approximately $2 million during the next twelve months.

Interest Rate Swap Agreements

FirstEnergy enters into fixed-to-floating interest rate swap agreements as part of its ongoing effort to manage the interest rate risk of its debt portfolio. These derivatives are treated as fair value hedges of fixed-rate, long-term debt issues protecting against the risk of changes in the fair value of fixed-rate debt instruments due to lower interest rates. Swap maturities, call options, fixed interest rates and interest payment dates match those of the underlying obligations. As a result of the differences between fixed and variable debt rates, interest expense was $10 million lower in the third quarter of 2004, compared to being $5 million lower in the third quarter of 2003. As of September 30, 2004, the debt underlying the interest rate swaps had a weighted average fixed interest rate of 5.53%, which the swaps have effectively converted to a current weighted average variable interest rate of 3.02%.

	September 30, 2004			**December 31, 2003**		
Interest Rate Swaps	**Notional Amount**	**Maturity Date**	**Fair Value**	**Notional Amount**	**Maturity Date**	**Fair Value**
	(Dollars in millions)					
Fixed to Floating Rate (Fair value hedges)	$ 200	2006	$ 1	$ 200	2006	$ 1
	100	2008		50	2008	
	100	2010	1	100	2010	1
	100	2011	3	100	2011	1
	450	2013	9	350	2013	(1)
	100	2014	3			
	150	2015	(6)	150	2015	(10)
	200	2016	10			
	150	2018	6	150	2018	1
	50	2019	3	50	2019	1
	100	2031	(3)			
	$1,700		$27	$1,150		$ (6)
Floating to Fixed Rate (1) (Cash flow hedges)				$ 7	2005	$

(1) FirstEnergy no longer had the cash flow hedges as of January 30, 2004 as a result of the divestiture of Los Amigos Leasing Company, Ltd. a subsidiary of GPU Power.

Equity Price Risk

Included in nuclear decommissioning trust investments are marketable equity securities carried at their market value of approximately $857 million and $779 million as of September 30, 2004 and December 31, 2003, respectively. A hypothetical 10% decrease in prices quoted by stock exchanges would result in an $86 million reduction in fair value as of September 30, 2004.

CREDIT RISK

Credit risk is the risk of an obligor s failure to meet the terms of any investment contract, loan agreement or otherwise perform as agreed. Credit risk arises from all activities in which success depends on issuer, borrower or counterparty performance, whether reflected on or off the balance sheet. FirstEnergy engages in transactions for the purchase and sale of commodities including gas, electricity, coal and emission allowances. These transactions are often with major energy companies within the industry.

FirstEnergy maintains credit policies with respect to its counterparties to manage overall credit risk. This includes performing independent risk evaluations, actively monitoring portfolio trends and using collateral and contract provisions to mitigate exposure. As part of its credit program, FirstEnergy manages the quality of its portfolio of energy contracts evidenced by a current weighted average risk rating for energy contract counterparties of BBB (S&P). As of September 30, 2004, the largest credit concentration with any counterparty relationship was 7% that counterparty is currently rated investment grade.

OUTLOOK

State Regulatory Matters

In Ohio, New Jersey and Pennsylvania, laws applicable to electric industry deregulation included similar provisions that are reflected in the EUOCs respective state regulatory plans. Those provisions include:

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allowing the EUOC s electric customers to select their generation suppliers;

establishing PLR obligations to non-shopping customers in the EUOC s service areas;

allowing recovery of potentially stranded investment (or transition costs) not otherwise recoverable in a competitive generation market;

itemizing (unbundling) the price of electricity into its component elements including generation, transmission, distribution and stranded costs recovery charges;

deregulating the EUOC s electric generation businesses;

continuing regulation of the EUOC s transmission and distribution systems; and

requiring corporate separation of regulated and unregulated business activities.

However, despite these similarities, the specific approach taken by each state and for each of the Companies varies.

Regulatory assets are costs which the respective regulatory agencies have authorized for recovery (or to be requested for authorization in the case of ATSI) from customers in future periods and, without such authorization, would have been charged to income when incurred. Regulatory assets are expected to continue to be recovered under the provisions of the respective transition and regulatory plans as discussed below. The regulatory assets of the individual companies are as follows:

Regulatory Assets	September 30, 2004	December 31, 2003	Increase (Decrease)
		(In millions)	
OE	$1,184	$1,451	$ (267)
CEI	983	1,056	(73)
TE	388	459	(71)
Penn	*	28	(28)
JCP&L	2,147	2,558	(411)
Met-Ed	785	1,028	(243)
Penelec	294	497	(203)
ATSI	12		12
Total	$5,793	$7,077	$(1,284)

* Changes in Penn s net regulatory asset components through September 2004 resulted in net regulatory liabilities of approximately $4 million included in Other Noncurrent Liabilities on the Consolidated Balance Sheet as of September 30, 2004.

Regulatory assets by source are as follows:

Increase

Regulatory Assets By Source	September 30, 2004	December 31, 2003	(Decrease)
		(In millions)	
Regulatory transition charge	$ 5,159	$ 6,427	$(1,268)
Customer shopping incentives	556	371	185
Customer receivables for future income taxes	268	340	(72)
Societal benefits charge	39	81	(42)
Loss on reacquired debt	89	75	14
Postretirement benefits	67	77	(10)
Nuclear decommissioning, decontamination and spent fuel disposal costs	(153)	(96)	(57)
Component removal costs	(333)	(321)	(12)
Property losses and unrecovered plant costs	55	70	(15)
Other	46	53	(7)
Total	$ 5,793	$ 7,077	$(1,284)

The Ohio Companies are deferring customer shopping incentives and interest costs as new regulatory assets in accordance with the transition and rate stabilization plans. These regulatory assets totaling $556 million as of September 30, 2004 (OE $205 million, CEI $271 million, TE $80 million) will be recovered through a surcharge rate equal to the RTC rate in effect when the transition costs have been fully recovered. Recovery of the new regulatory assets will begin at that time and amortization of the regulatory assets for each accounting period will be equal to the surcharge revenue recognized in each period.

Reliability Initiatives

On October 15, 2003, NERC issued a letter to all NERC control areas and reliability coordinators requesting a review of various reliability practices. FirstEnergy s response confirmed that its review was completed and that various enhancements were underway to current practices. On February 10, 2004, NERC issued its Recommended Actions to Prevent and Mitigate the Impacts of Future Cascading Blackouts, a portion of which were directed at the FirstEnergy companies and broadly focused on initiatives that were recommended for completion by June 30, 2004. FirstEnergy s detailed implementation plan was endorsed by the NERC Board of Trustees on May 7, 2004. The various initiatives recommended by NERC were certified as complete by June 30, 2004, with one minor exception related to reactive testing of certain generators expected to be completed later this year.

On February 26 and 27, 2004, certain FirstEnergy companies, as part of a NERC review of control area operations throughout the United States, participated in a NERC Control Area Readiness Audit. The final audit report, completed on May 6, 2004, identified positive observations and included various recommendations for reliability improvement. FirstEnergy reported completion of those recommendations on June 30, 2004, with one exception related to MISO s implementation of a voltage stability tool expected to be completed later this year.

On April 5, 2004, the U.S. Canada Power System Outage Task Force issued a Final Report on the August 14, 2003 power outages. The Final Report contains 46 recommendations to prevent or minimize the scope of future blackouts. Forty-five of those recommendations relate to broad industry or policy matters while one relates to activities the Task Force recommended be undertaken by FirstEnergy, MISO, PJM and ECAR. FirstEnergy completed the Task Force recommendations that were directed toward FirstEnergy and reported completion of those activities on June 30, 2004.

With respect to each of the foregoing initiatives, FirstEnergy requested and NERC provided, a technical assistance team of experts to provide ongoing guidance and assistance in implementing and confirming timely and successful completion. NERC further assembled an independent verification team to confirm implementation of the foregoing initiatives required to be completed as of June 30, 2004. The NERC Verification Team reported, on July 14, 2004, that FirstEnergy has completed the recommended policies, procedures and actions required to be completed by June 30, 2004 or summer 2004, with exceptions noted by FirstEnergy. Implementation of the recommendations has not required incremental material investment or upgrades to existing equipment.

On March 1, 2004, certain FirstEnergy companies filed, in accordance with a November 25, 2003 order from the PUCO, their plan for addressing certain issues identified by the PUCO from the U.S. Canada Power System Outage Task Force interim report. In particular, the filing addressed upgrades to FirstEnergy s control room computer hardware and software and enhancements to the training of control room operators. The PUCO will review the plan before determining the next steps, if any, in the proceeding.

On April 22, 2004, FirstEnergy filed with the FERC the results of the FERC-ordered independent study of part of Ohio s power grid. The study examined, among other things, the reliability of the transmission grid in critical points in the Northern Ohio area and the need, if any, for reactive power reinforcements during summers 2004 and 2009. Certain requested additional clarifications were provided to the FERC in October 2004. FirstEnergy completed the implementation of recommendations relating to 2004 by June 30, 2004, and is continuing to review results related to 2009. The estimated capital expenditures required by 2009 are not expected to have a material adverse effect on FirstEnergy s financial results. FirstEnergy notes, however, that FERC or other applicable government agencies and reliability coordinators may take a different view as to recommended enhancements or may recommend additional enhancements in the future that could require additional, material expenditures.

In late 2003, the PPUC issued a Tentative Order implementing new reliability benchmarks and standards. In connection therewith, the PPUC commenced a rulemaking procedure to amend the Electric Service Reliability Regulations to implement these new benchmarks, and required additional reporting on reliability. The PPUC ordered all Pennsylvania utilities to begin filing quarterly reports on November 1, 2003. On May 11, 2004, the PPUC issued an order approving the revised reliability benchmark and standards, including revised benchmarks and standards for Met-Ed, Penelec and Penn. The Order permitted Pennsylvania utilities to file in a separate proceeding to revise the recomputed benchmarks and standards if they have evidence, such as the impact of automated outage management systems, on the accuracy of the PPUC computed reliability indices. Met-Ed, Penelec and Penn filed a Petition for Amendment of Benchmarks with the PPUC on May 26, 2004, seeking amendment of the benchmarks and standards due to their implementation of automated outage management systems following restructuring. No procedural schedule or hearing date has been set for this proceeding. FirstEnergy is unable to predict the outcome of this proceeding.

On January 16, 2004, the PPUC initiated a formal investigation of whether Met-Ed s, Penelec s and Penn s service reliability performance deteriorated to a point below the level of service reliability that existed prior to restructuring in Pennsylvania. Hearings were held in early August 2004. On September 30, 2004, Met-Ed, Penelec and Penn filed a settlement agreement with the PPUC that addresses the issues related to this investigation. As part of the settlement, Met-Ed, Penelec and Penn agreed to enhance service reliability, performance reporting and communications with customers and to collectively maintain their current spending levels of at least $255 million annually on combined capital and operation and maintenance expenditures for transmission and distribution for the years 2005 through 2007. In November 2004, the PPUC accepted the recommendation of the ALJ approving the settlement.

Ohio

FirstEnergy s transition plan for the Ohio Companies included approval for recovery of transition costs, including regulatory assets, through no later than 2006 for OE, mid-2007 for TE and 2008 for CEI, except where a longer period of recovery is provided for in the settlement agreement; granting preferred access over its subsidiaries to nonaffiliated marketers, brokers and aggregators, to 1,120 MW of generation capacity through 2005 at established prices for sales to the Ohio Companies retail customers; and freezing customer prices through a five-year market development period (2001-2005), except for certain limited statutory exceptions including a 5% reduction in the price of generation for residential customers.

The Ohio Companies customers choosing alternative suppliers receive an additional incentive applied to the shopping credit (generation component) of 45% for residential customers, 30% for commercial customers and 15% for industrial customers. The amount of the incentive is deferred for future recovery from customers through an extension of the regulatory transition charge.

On October 21, 2003, the Ohio Companies filed an application with the PUCO to establish generation service rates beginning January 1, 2006, in response to expressed concerns by the PUCO about price and supply uncertainty following the end of the market development period. The filing included two options:

- A competitive auction, which would establish a price for generation that customers would be charged during the period covered by the auction, or

- A Rate Stabilization Plan, which would extend current generation prices through 2008, ensuring adequate generation supply at stable prices, and continuing the Ohio Companies support of energy efficiency and economic development efforts.

Under that proposal, the Ohio Companies requested:

- Extension of the transition cost amortization period for OE from 2006 to 2007; for CEI from 2008 to 2009 and for TE from mid-2007 to 2008;

- Deferral of interest costs on the accumulated shopping incentives and other cost deferrals as new regulatory assets; and

- Ability to initiate a request to increase generation rates under certain limited conditions.

On February 23, 2004, after consideration of the PUCO Staff comments and testimony as well as those provided by some of the intervening parties, the Ohio Companies made certain modifications to the Rate Stabilization Plan. On June 9, 2004, the PUCO issued an order approving the revised Rate Stabilization Plan, subject to conducting a competitive bid process on or before December 1, 2004. In addition to requiring the competitive bid process, the PUCO made other modifications to the Ohio Companies revised Rate Stabilization Plan application. Among the major modifications were the following:

- Limiting the ability of the Ohio Companies to request adjustments in generation charges during 2006 through 2008 for increases in taxes;

Expanding the availability of market support generation;

Revising the kilowatt-hour target level and the time period for recovering regulatory transition charges;

Establishing a 3-year competitive bid process for generation;

Establishing the 2005 generation credit for shopping customers, which would be extended as a cap through 2008; and

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Denying the ability to defer costs for future recovery of distribution reliability improvement expenditures.

On June 18, 2004, the Ohio Companies filed with the PUCO an application for rehearing of the modified version of the Rate Stabilization Plan. Several other parties also filed applications for rehearing. On August 4, 2004, the PUCO issued an Entry on Rehearing modifying its June 9, 2004 Order. The modifications included the following:

Expanding the Ohio Companies ability to request adjustments in generation charges during 2006 through 2008 to include increases in the cost of fuel (including the cost of emission allowances consumed, lime, stabilizers and other additives and fuel disposal) using 2002 as the base year. Any increases in fuel costs would be subject to downward adjustments in subsequent years should fuel costs decline, but not below the generation rate initially established in the Rate Stabilization Plan;

Approving the revised kilowatt-hour target level and time period for recovery of regulatory transition costs as presented by the Ohio Companies in their rehearing application;

Retaining the requirement for expanded availability of market support generation, but adopting the Ohio Companies alternative approach that conditions expanded availability on higher pricing and eliminating the requirement to reduce the interest deferral for certain affected rate schedules;

Revising the calculation of the shopping credit cap for certain commercial and small industrial rate schedules; and

Relaxing the notice requirement for availability of enhanced shopping credits in a number of instances.

On August 5, 2004, the Ohio Companies accepted the Rate Stabilization Plan as modified and approved by the PUCO on August 4, 2004. The Ohio Companies retains the right to withdraw the modified Rate Stabilization Plan should subsequent adverse action be taken by the PUCO or a court. In the second quarter of 2004, the Ohio Companies implemented the accounting modifications contained in the PUCO s June 9, 2004 Order, which are consistent with the PUCO s August 4, 2004 Entry on Rehearing. Those modifications included amortization of transition costs based on extended amortization periods (that are no later than 2007 for OE, mid-2009 for CEI and mid-2008 for TE) and the deferral of interest costs on the accumulated deferred shopping incentives. On October 1, 2004, the OCC filed an appeal with the Ohio Supreme Court to overturn the June 9, 2004 PUCO order.

The Ohio Companies filed a proposed competitive bid process which the PUCO modified on October 6, 2004. The PUCO approved the rules for the competitive bid process setting a three-year supply period (2006-2008) requirement for generation service suppliers and a load cap for individual suppliers. In mid-October, the initial auction schedule was revised so that Part 1 and Part 2 auction bidder applications are due November 4, 2004 and November 15, respectively, the trial auction is scheduled to occur on December 3, the auction would commence December 8 and the PUCO will accept or reject auction results within two business days after the completion of the auction. FirstEnergy has elected to not participate in the auction.

New Jersey

Under New Jersey transition legislation, all electric distribution companies were required to file rate cases to determine the level of unbundled rate components to become effective August 1, 2003. JCP&L s two August 2002 rate filings requested increases in base electric rates of approximately $98 million annually and requested the recovery of deferred energy costs that exceeded amounts being recovered under the current MTC and SBC rates; one proposed method of recovery of these costs is the securitization of the deferred balance. This securitization methodology is similar to the Oyster Creek securitization. On July 25, 2003, the NJBPU announced its JCP&L base electric rate proceeding decision, which reduced JCP&L s annual revenues by approximately $62 million effective August 1, 2003. The NJBPU decision also provided for an interim return on equity of 9.5% on JCP&L s rate base for the subsequent six to twelve months. During that period, the decision also required that, within approximately one year of its issuance, JCP&L would initiate another proceeding to request recovery of additional costs incurred to enhance system reliability. In that Phase II proceeding, the NJBPU could increase JCP&L s return on equity to 9.75% or decrease it to 9.25%, depending on its assessment of the reliability of JCP&L s service. Any reduction would be retroactive to August 1, 2003. The net revenue decrease from the NJBPU s decision consists of a $223 million decrease in the electricity delivery charge, a $111 million increase due to the August 1, 2003 expiration of annual customer credits previously mandated by the New Jersey transition legislation, a $49 million increase in the MTC tariff component, and a net $1 million increase in the SBC. The decision in the deferred balances proceeding disallowed $153 million of deferred energy costs, so that the MTC allows for the recovery of $465 million in deferred energy costs over the next ten years on an interim basis. As a result, JCP&L

recorded charges to net income for the year ended December 31, 2003, aggregating $185 million ($109 million net of tax) consisting of the $153 million of disallowed deferred energy costs and $32 million of other disallowed regulatory assets. JCP&L filed an interim motion for rehearing and reconsideration with the NJBPU on August 15, 2003 with respect to the following issues: (1) the disallowance of the $153 million deferred energy costs; (2) the reduced rate of return on equity; and (3) $42.7 million of disallowed costs to achieve merger savings. In its final decision and order issued on May 17, 2004, the NJPBU clarified the method for calculating interest attributable to the cost disallowances, resulting in a $5.4 million reduction from the amount estimated in 2003. On June 1, 2004, JCP&L filed with the NJBPU a supplemental and amended motion for rehearing and reconsideration. On July 7, 2004, the NJBPU granted limited reconsideration and rehearing on the following issues: (1) deferred cost disallowances, (2) the capital structure including the rate of return, (3) merger savings, including amortization of costs to achieve merger savings; and (4) decommissioning. All other issues included in JCP&L s amended motion were denied. Oral arguments were held on August 4, 2004. Management is unable to predict when a decision may be reached by the NJBPU.

On July 5, 2003, JCP&L experienced a series of 34.5 kilovolt sub-transmission line faults that resulted in outages on the New Jersey shore. The NJBPU instituted an investigation into these outages, and directed that a Special Reliability Master (SRM) be hired to oversee the investigation. On December 8, 2003, the SRM issued his Interim Report recommending that JCP&L implement a series of actions to improve reliability in the area affected by the outages. The NJBPU adopted the findings and recommendations of the Interim Report on December 17, 2003, and ordered JCP&L to implement the recommended actions on a staggered basis, with initial actions to be completed by March 31, 2004. In late 2003, in accordance with a Settlement Stipulation concerning an August 2002 storm outage, the NJBPU engaged Booth & Associates to conduct an audit of the planning, operations and maintenance practices, policies and procedures of JCP&L. The audit was expanded to include the July 2003 outage and was completed in January 2004. On June 9, 2004, the NJBPU approved a stipulation that incorporated the final SRM report and portions of the final Booth report. The final order was issued by the NJBPU on July 23, 2004.

On July 16, 2004, JCP&L filed the Phase II rate filing with the NJBPU which requested an increase in base rates of $36 million, reflecting the recovery of system reliability costs and a 9.75% return on equity. The filing also requests an increase to the MTC deferred balance recovery of approximately $20 million annually. Discovery/settlement conferences are ongoing. The filing fulfills the NJBPU requirement that a Phase II proceeding be conducted and that any expenditures and projects undertaken by JCP&L to increase its system reliability be reviewed.

JCP&L sells all self-supplied energy (NUGs and owned generation) to the wholesale market with offsetting credits to its deferred energy balances with the exception of 300 MW from JCP&L s must run NUG committed supply currently being used to serve BGS customers pursuant to NJBPU order. The BGS auction for periods beginning June 1, 2004 was completed in February 2004 and new BGS tariffs reflecting the auction results became effective June 1, 2004. On May 25, 2004, the NJBPU issued an order adopting a schedule for the BGS post transition year three process. JCP&L filed its proposal suggesting how BGS should be procured for year three and beyond. The NJBPU decision on the filing was announced on October 22, 2004, approving with minor modifications the BGS procurement process filed by JCP&L and the other New Jersey electric distribution companies and authorizing the continued use of NUG committed supply to serve 300 MW of BGS load. The auction is scheduled to take place in February 2005 for the supply period beginning June 1, 2005.

In accordance with an April 28, 2004 NJBPU order, JCP&L filed testimony on June 7, 2004 supporting a continuation of the current level and duration of the funding of TMI-2 decommissioning costs by New Jersey ratepayers without a reduction, termination or capping of the funding. On September 30, 2004, JCP&L filed an updated TMI-2 decommissioning study prepared by TLG Services, Inc. (see Note 2 Asset Retirement Obligations). This study resulted in an updated total decommissioning cost estimate of $729 million (in 2003 dollars) compared to the estimated $528 million (in 2003 dollars) from the prior 1995 decommissioning study.

Pennsylvania

In June 2001, the PPUC approved the Settlement Stipulation with all of the major parties in the combined merger and rate relief proceedings which approved the FirstEnergy/GPU merger and provided PLR deferred accounting treatment for energy costs, permitting Met-Ed and Penelec to defer, for future recovery, energy costs in excess of amounts reflected in their capped generation rates retroactive to January 1, 2001. This PLR deferral accounting procedure was later reversed in a February 2002 Commonwealth Court of Pennsylvania decision. The court decision also affirmed the PPUC decision regarding approval of the merger, remanding the decision to the PPUC only with respect to the issue of merger savings. FirstEnergy established reserves in 2002 for Met-Ed s and Penelec s PLR deferred energy costs which aggregated $287.1 million, reflecting the potential adverse impact of the then pending Pennsylvania Supreme Court decision whether to review the Commonwealth Court decision. FirstEnergy recorded in 2002 an aggregate non-cash charge of $55.8 million ($32.6 million net of tax) to income for the deferred costs incurred subsequent to the merger. The reserve for the remaining $231.3 million of deferred costs increased goodwill by an aggregate net of tax amount of $135.3 million.

On April 2, 2003, the PPUC remanded the issue relating to merger savings to the ALJ for hearings, directed Met-Ed and Penelec to file a position paper on the effect of the Commonwealth Court order on the Settlement Stipulation and allowed other parties to file responses to the position paper. Met-Ed and Penelec filed a letter with the ALJ on June 11, 2003, voiding the Stipulation in its entirety and reinstating Met-Ed s and Penelec s restructuring settlement previously approved by the PPUC.

On October 2, 2003, the PPUC issued an order concluding that the Commonwealth Court reversed the PPUC s June 20, 2001 order in its entirety. The PPUC directed Met-Ed and Penelec to file tariffs within thirty days of the order to reflect the CTC rates and shopping credits that were in effect prior to the June 21, 2001 order to be effective upon one day s notice. In response to that order, Met-Ed and Penelec filed supplements to their tariffs to become effective October 24, 2003.

On October 8, 2003, Met-Ed and Penelec filed a petition for clarification relating to the October 2, 2003 order on two issues: to establish June 30, 2004 as the date to fully refund the NUG trust fund and to clarify that the ordered accounting treatment regarding the CTC rate/shopping credit swap should follow the ratemaking, and that the PPUC s findings would not impair their rights to recover all of their stranded costs. On October 9, 2003, ARIPPA (an intervenor in the proceedings) petitioned the PPUC to direct Met-Ed and Penelec to reinstate accounting for the CTC rate/shopping credit swap retroactive to January 1, 2002. Several other parties also filed petitions. On October 16, 2003, the PPUC issued a reconsideration order granting the date requested by Met-Ed and Penelec for the NUG trust fund refund, denying Met-Ed s and Penelec s other clarification requests and granting ARIPPA s petition with respect to the retroactive accounting treatment of the changes to the CTC rate/shopping credit swap. On October 22, 2003, Met-Ed and Penelec filed an Objection with the Commonwealth Court asking that the Court reverse the PPUC s finding that requires Met-Ed and Penelec to treat the stipulated CTC rates that were in effect from January 1, 2002 on a retroactive basis.

On October 27, 2003, one Commonwealth Court judge issued an Order denying Met-Ed s and Penelec s Objection without explanation. Due to the vagueness of the Order, Met-Ed and Penelec, on October 31, 2003, filed an Application for Clarification with the judge. Concurrent with this filing, Met-Ed and Penelec, in order to preserve their rights, also filed with the Commonwealth Court both a Petition for Review of the PPUC s October 2 and October 16 Orders, and an application for reargument, if the judge, in his clarification order, indicates that Met-Ed s and Penelec s Objection was intended to be denied on the merits. In addition to these findings, Met-Ed and Penelec, in compliance with the PPUC s Orders, filed revised PPUC quarterly reports for the twelve months ended December 31, 2001 and 2002, and for the first two quarters of 2003, reflecting balances consistent with the PPUC s findings in their Orders.

Met-Ed and Penelec purchase a portion of their PLR requirements from FES through a wholesale power sale agreement. The PLR sale is automatically extended for each successive calendar year unless any party elects to cancel the agreement by November 1 of the preceding year. Under the terms of the wholesale agreement, FES retains the supply obligation and the supply profit and loss risk, for the portion of power supply requirements not self-supplied by Met-Ed and Penelec under their NUG contracts and other power contracts with nonaffiliated third party suppliers. This arrangement reduces Met-Ed s and Penelec s exposure to high wholesale power prices by providing power at a fixed price for their uncommitted PLR energy costs during the term of the agreement with FES. FES has hedged most of Met-Ed s and Penelec s unfilled PLR on-peak obligation through 2004 and a portion of 2005, the period during which deferred accounting was previously allowed under the PPUC s order. Met-Ed and Penelec are authorized to continue deferring differences between NUG contract costs and current market prices.

Environmental Matters

Various federal, state and local authorities regulate the Companies with regard to air and water quality and other environmental matters. The effects of compliance on the Companies with regard to environmental matters could have a material adverse effect on FirstEnergy s earnings and competitive position. These environmental regulations affect FirstEnergy s earnings and competitive position to the extent that it competes with companies that are not subject to such regulations and therefore do not bear the risk of costs associated with compliance, or failure to comply, with such regulations. Overall, FirstEnergy believes it is in material compliance with existing regulations but is unable to predict future change in regulatory policies and what, if any, the effects of such change would be.

The EPA has proposed the Interstate Air Quality Rule to cap-and-trade NO_x and SO_2 emissions in two phases (Phase I in 2010 and Phase II in 2015). According to the EPA, SO_2 emissions would be reduced by approximately 3.6 million tons in 2010, across states covered by the rule, with reductions ultimately reaching more than 5.5 million tons annually. NO_x emission reductions would measure about 1.5 million tons in 2010 and 1.8 million tons in 2015. The future cost of compliance with these proposed regulations may be substantial and will depend on whether and how they are ultimately implemented by the states in which the Companies operate affected facilities.

On December 15, 2003, the EPA proposed two different approaches to reduce mercury emissions from coal-fired power plants. The first approach would require plants to install controls known as maximum achievable control technologies (MACT) based on the type of coal burned. According to the EPA, if implemented, the MACT proposal would reduce nationwide mercury emissions from coal-fired power plants by 14 tons to approximately 34 tons per year. The second approach proposes a cap-and-trade program that would reduce mercury emissions in two distinct phases. Initially, mercury emissions would be reduced by 2010 as a co-benefit from implementation of SO_2 and NO_x emission caps under the EPA s proposed Interstate Air Quality Rule. Phase II of the mercury cap-and-trade program would be implemented in 2018 to cap nationwide mercury emissions from coal-fired power plants at 15 tons per year. The EPA has agreed to choose between these two options and issue a final rule by March 15, 2005. The future cost of compliance with these regulations may be substantial.

In 1999 and 2000, the EPA issued NOV or Compliance Orders to nine utilities covering 44 power plants, including the W. H. Sammis Plant which is owned by OE and Penn. In addition, the U.S. Department of Justice filed eight civil complaints against various investor-owned utilities, which included a complaint against OE and Penn in the U.S. District Court for the Southern District of Ohio. These cases are referred to as New Source Review cases. The NOV and complaint allege violations of the Clean Air Act based on operation and maintenance of the W. H. Sammis Plant dating back to 1984. The complaint requests permanent injunctive relief to require the installation of best available control technology and civil penalties of up to $27,500 per day of violation. On August 7, 2003, the United States District Court for the Southern District of Ohio ruled that 11 projects undertaken at the W. H. Sammis Plant between 1984 and 1998 required pre-construction permits under the Clean Air Act. The ruling concludes the liability phase of the case, which deals with applicability of Prevention of Significant Deterioration provisions of the Clean Air Act. The remedy phase trial to address civil penalties and what, if any, actions should be taken to further reduce emissions at the plant has been rescheduled to January 2005 by the Court because the parties are engaged in meaningful settlement negotiations. The Court indicated in its August 2003 ruling that the remedies it may consider and impose involved a much broader, equitable analysis, requiring the Court to consider air quality, public health, economic impact, and employment consequences. The Court may also consider the less than consistent efforts of the EPA to apply and further enforce the Clean Air Act. The potential penalties that may be imposed, as well as the capital expenditures necessary to comply with substantive remedial measures that may be required, could have a material adverse impact on FirstEnergy s, OE s and Penn s respective financial condition and results of operations. While the parties are engaged in meaningful settlement discussions, management is unable to predict the ultimate outcome of this matter and no liability has been accrued as of September 30, 2004.

In December 1997, delegates to the United Nations climate summit in Japan adopted an agreement, the Kyoto Protocol (Protocol), to address global warming by reducing the amount of man-made greenhouse gases emitted by developed countries by 5.2% from 1990 levels between 2008 and 2012. The United States signed the Protocol in 1998 but it failed to receive the two-thirds vote of the U.S. Senate required for ratification. However, the Bush administration has committed the United States to a voluntary climate change strategy to reduce domestic greenhouse gas intensity the ratio of emissions to economic output by 18% through 2012. The Companies cannot currently estimate the financial impact of climate change policies, although the potential restrictions on CO_2 emissions could require significant capital and other expenditures. However, the CO_2 emissions per kilowatt-hour of electricity generated by the Companies is lower than many regional competitors due to the Companies diversified generation sources which includes low or non-CO_2 emitting gas-fired and nuclear generators.

On September 7, 2004, the EPA established new performance standards under Clean Water Act Section 316(b) for reducing impacts on fish and shellfish from cooling water intake structures at certain existing large electric generating plants. The regulations call for reductions in impingement mortality, when aquatic organisms are pinned against screens or other parts of a cooling water intake system and entrainment, which occurs when aquatic species are drawn into a facility s cooling water system. The Companies are conducting comprehensive demonstration studies, due in 2008, to determine the operational measures, equipment or restoration activities, if any, necessary for compliance by their facilities with the performance standards. FirstEnergy is unable to predict the outcome of such studies. Depending on the outcome of such studies, the future cost of compliance with these standards may be substantial.

Power Outages and Related Litigation

In July 1999, the Mid-Atlantic states experienced a severe heat wave which resulted in power outages throughout the service territories of many electric utilities, including JCP&L s territory. In an investigation into the causes of the outages and the reliability of the transmission and distribution systems of all four New Jersey electric utilities, the NJBPU concluded that there was not a prima facie case demonstrating that, overall, JCP&L provided unsafe, inadequate or improper service to its customers. Two class action lawsuits (subsequently consolidated into a single proceeding) were filed in New Jersey Superior Court in July 1999 against JCP&L, GPU and other GPU companies, seeking compensatory and punitive damages arising from the July 1999 service interruptions in the JCP&L territory.

In August 2002, the trial court granted partial summary judgment to JCP&L and dismissed the plaintiffs claims for consumer fraud, common law fraud, negligent misrepresentation, and strict products liability. In November 2003, the trial court granted JCP&L s motion to decertify the class and denied plaintiffs motion to permit into evidence their class-wide damage model indicating damages in excess of $50 million. These class decertification and damage rulings were appealed to the Appellate Division. The Appellate Court issued a decision on July 8, 2004, affirming the decertification of the originally certified class but remanding for certification of a class limited to those customers directly impacted by the outages of transformers in Red Bank, New Jersey. On September 8, 2004, the New Jersey Supreme Court denied the motions filed by plaintiffs and JCP&L for leave to appeal the decision of the Appellate Court. FirstEnergy is unable to predict the outcome of these matters and no liability has been accrued as of September 30, 2004.

On August 14, 2003, various states and parts of southern Canada experienced widespread power outages. The outages effected approximately 1.4 million customers in FirstEnergy s service area. On April 5, 2004, the U.S. Canada Power System Outage Task Force released its final report on the outages. In the final report, the Task Force concluded, among other things, that the problems leading to the outages began in FirstEnergy s Ohio service area. Specifically, the final report concludes, among other things, that the initiation of the August 14, 2003 power outages resulted from an alleged failure of both FirstEnergy and ECAR to assess and understand perceived inadequacies within the FirstEnergy system; inadequate situational awareness of the developing conditions; and a perceived failure to adequately manage tree growth in certain transmission rights of way. The Task Force also concluded that there was a failure of the interconnected grid s reliability organizations (MISO and PJM) to provide effective diagnostic support. The final report is publicly available through the Department of Energy s website (www.doe.gov). FirstEnergy believes that the final report does not provide a complete and comprehensive picture of the conditions that contributed to the August 14, 2003 power outages and that it does not adequately address the underlying causes of the outages. FirstEnergy remains convinced that the outages cannot be explained by events on any one utility s system. The final report contains 46 recommendations to prevent or minimize the scope of future blackouts. Forty-five of those recommendations relate to broad industry or policy matters while one, including subparts, relates to activities the Task Force recommends be undertaken by FirstEnergy, MISO, PJM, and ECAR. FirstEnergy implemented several initiatives, both prior to and since the August 14, 2003 power outages, which are consistent with these and other recommendations and collectively enhance the reliability of its electric system. FirstEnergy certified to NERC on June 30, 2004, completion of various reliability recommendations and further received independent verification of completion status from a NERC verification team on July 14, 2004 (see Reliability Initiatives above). FirstEnergy s implementation of these recommendations included completion of the Task Force recommendations that were directed toward FirstEnergy. As many of these initiatives already were in process and budgeted in 2004, FirstEnergy does not believe that any incremental expenses associated with additional initiatives undertaken during 2004 will have a material effect on its operations or financial results. FirstEnergy notes, however, that the applicable government agencies and reliability coordinators may take a different view as to recommended enhancements or may recommend additional enhancements in the future that could require additional, material expenditures. FirstEnergy has not accrued a liability as of September 30, 2004 for any expenditures in excess of those actually incurred through that date.

Three substantially similar actions were filed in various Ohio state courts by plaintiffs seeking to represent customers who allegedly suffered damages as a result of the August 14, 2003 power outages. All three cases were dismissed for lack of jurisdiction. One case was refiled at the PUCO and the other two have been appealed. In addition to the one case that was refiled at the PUCO, the Ohio Companies were named as respondents in a regulatory proceeding that was initiated at the PUCO in response to complaints alleging failure to provide reasonable and adequate service stemming primarily from the August 14, 2003 power outages.

One complaint has been filed against FirstEnergy in the New York State Supreme Court. In this case, several plaintiffs in the New York City metropolitan area allege that they suffered damages as a result of the August 14, 2003 power outages. None of the plaintiffs are customers of any FirstEnergy affiliate. FirstEnergy filed a motion to dismiss with the Court on October 22, 2004. No damage estimate has been provided and thus potential liability has not been determined.

FirstEnergy is vigorously defending these actions, but cannot predict the outcome of any of these proceedings or whether any further regulatory proceedings or legal actions may be instituted against the Companies. In particular, if FirstEnergy or its subsidiaries were ultimately determined to have legal liability in connection with these proceedings, it could have a material adverse effect on FirstEnergy s or its subsidiaries financial condition and results of operations.

Nuclear Plant Matters

FENOC received a subpoena in late 2003 from a grand jury sitting in the United States District Court for the Northern District of Ohio, Eastern Division requesting the production of certain documents and records relating to the inspection and maintenance of the reactor vessel head at the Davis-Besse plant. FirstEnergy is unable to predict the outcome of this investigation. In addition, FENOC remains subject to possible civil enforcement action by the NRC in connection with the events leading to the Davis-Besse outage in 2002. Further, a petition was filed with the NRC on March 29, 2004 by a group objecting to the NRC s restart order of the Davis-Besse Nuclear Power Station. The Petition seeks, among other things, suspension of the Davis-Besse operating license. A June 2, 2004 ASLB denial of the petition was appealed to the NRC. FENOC and the NRC staff filed opposition briefs on June 24, 2004. If it were ultimately determined that FirstEnergy or its subsidiaries has legal liability or is otherwise made subject to enforcement action based on the Davis-Besse outage, it could have a material adverse effect on FirstEnergy s or its subsidiaries financial condition and results of operations.

On August 12, 2004, the NRC publicly disclosed that it was notifying FirstEnergy that it will increase its regulatory oversight of the Perry Nuclear Power Plant as a result of problems with safety system equipment over the past two years. OE, CEI, TE and Penn own and/or lease the Perry Nuclear Power Plant. The NRC noted that the plant continues to operate safely. The increased oversight will include an extensive NRC team inspection to access the equipment problems and FirstEnergy s corrective actions. The outcome of this increased oversight is not known at this time.

Other Legal Matters

Various lawsuits, claims (including claims for asbestos exposure) and proceedings related to FirstEnergy s normal business operations are pending against FirstEnergy and its subsidiaries. The most significant not otherwise discussed above are described below.

On October 20, 2004, FirstEnergy was notified by the SEC that the previously disclosed informal inquiry initiated by the SEC s Division of Enforcement in September 2003 relating to the restatements in August 2003 of previously reported results by FirstEnergy and the Ohio Companies and the Davis-Besse extended outage has become the subject of a formal order of investigation. The SEC s formal order of investigation also encompasses issues raised during the SEC s examination of FirstEnergy and the Companies under the PUHCA. Concurrent with this notification, FirstEnergy received a subpoena asking for background documents and documents related to the restatements and Davis-Besse issues. FirstEnergy has cooperated fully with the informal inquiry and will continue to do so with the formal investigation.

Various legal proceedings alleging violations of federal securities laws and related state laws were filed against FirstEnergy in connection with, among other things, the restatements in August 2003 by FirstEnergy and the Ohio Companies of previously reported results, the August 14, 2003 power outages described above, and the extended outage at the Davis-Besse Nuclear Power Station. The lawsuits were filed against FirstEnergy and certain of its officers and directors. On July 27, 2004, FirstEnergy announced that it had reached an agreement to resolve these pending lawsuits. The settlement agreement, which does not constitute any admission of wrongdoing, provides for a total settlement payment of $89.9 million. Of that amount, FirstEnergy s insurance carriers will pay $71.92 million, based on a contractual pre-allocation, and FirstEnergy will pay $17.98 million, which resulted in an after-tax charge against FirstEnergy s second quarter and year-to-date 2004 earnings of $11 million or $0.03 per share of common stock (basic and diluted). The settlement has been preliminarily approved by the court with a final hearing scheduled for mid-December 2004. Although not anticipated to occur, in the event that a significant number of shareholders do not accept the terms of the settlement, FirstEnergy and individual defendants have the right, but not the obligation, to set aside the settlement and recommence the litigation.

On September 16, 2004, the FERC issued an order that imposed additional obligations on CEI under certain pre-Open Access transmission contracts among CEI and the cities of Cleveland and Painesville. Under the FERC s decision, CEI may be responsible for a portion of new energy market charges imposed by the MISO when its energy markets begin in the spring of 2005. CEI filed for rehearing of the order from the FERC on October 18, 2004. The impact of the FERC decision on CEI is dependent upon many factors, including the arrangements made by the cities for transmission service, the startup date for the MISO energy market, and the resolution of the rehearing request, and cannot be determined at this time.

If it were ultimately determined that FirstEnergy or its subsidiaries has legal liability or is otherwise made subject to liability based on any of the above matters, it could have a material adverse effect on FirstEnergy s or its subsidiaries financial condition and results of operations.

CRITICAL ACCOUNTING POLICIES

FirstEnergy prepares its consolidated financial statements in accordance with GAAP. Application of these principles often requires a high degree of judgment, estimates and assumptions that affect financial results. All of FirstEnergy s assets are subject to their own specific risks and uncertainties and are regularly reviewed for impairment. Assets related to the application of the policies discussed below are similarly reviewed with their risks and uncertainties reflecting these specific factors. FirstEnergy s more significant accounting policies are described below.

Regulatory Accounting

FirstEnergy s regulated services segment is subject to regulation that sets the prices (rates) it is permitted to charge its customers based on costs that the regulatory agencies determine FirstEnergy is permitted to recover. At times, regulators permit the future recovery through rates of costs that would be currently charged to expense by an unregulated company. This rate-making process results in the recording of regulatory assets based on anticipated future cash inflows. FirstEnergy regularly reviews these assets to assess their ultimate recoverability within the approved regulatory guidelines. Impairment risk associated with these assets relates to potentially adverse legislative, judicial or regulatory actions in the future.

Derivative Accounting

Determination of appropriate accounting for derivative transactions requires the involvement of management representing operations, finance and risk assessment. In order to determine the appropriate accounting for derivative transactions, the provisions of the contract need to be carefully assessed in accordance with the authoritative accounting literature and management s intended use of the derivative. New authoritative guidance continues to shape the application of derivative accounting. Management s expectations and intentions are key factors in determining the appropriate accounting for a derivative transaction and, as a result, such expectations and intentions are documented. Derivative contracts that are determined to fall within the scope of SFAS 133, as amended, must be recorded at their fair value. Active market prices are not always available to determine the fair value of the later years of a contract, requiring that various assumptions and estimates be used in their valuation. FirstEnergy continually monitors its derivative contracts to determine if its activities, expectations, intentions, assumptions and estimates remain valid. As part of its normal operations, FirstEnergy enters into a significant number of commodity contracts, as well as interest rate swaps, which increase the impact of derivative accounting judgments.

Revenue Recognition

FirstEnergy follows the accrual method of accounting for revenues, recognizing revenue for electricity that has been delivered to customers but not yet billed through the end of the accounting period. The determination of electricity sales to individual customers is based on meter readings, which occur on a systematic basis throughout the month. At the end of each month, electricity delivered to customers since the last meter reading is estimated and a corresponding accrual for unbilled revenues is recognized. The determination of unbilled revenues requires management to make estimates regarding electricity available for retail load, transmission and distribution line losses, demand by customer class, weather-related impacts and electricity provided by alternative suppliers.

Pension and Other Postretirement Benefits Accounting

FirstEnergy s reported costs of providing non-contributory defined pension benefits and postemployment benefits other than pensions are dependent upon numerous factors resulting from actual plan experience and certain assumptions.

Pension and OPEB costs are affected by employee demographics (including age, compensation levels, and employment periods), the level of contributions FirstEnergy makes to the plans, and earnings on plan assets. Such factors may be further affected by business combinations (such as FirstEnergy s merger with GPU in November 2001), which impacts employee demographics, plan experience and other factors. Pension and OPEB costs are also affected by changes to key assumptions, including anticipated rates of return on plan assets, the discount rates and health care trend rates used in determining the projected benefit obligations for pension and OPEB costs.

In accordance with SFAS 87 and SFAS 106, changes in pension and OPEB obligations associated with these factors may not be immediately recognized as costs on the income statement, but generally are recognized in future years over the remaining average service period of plan participants. SFAS 87 and SFAS 106 delay recognition of changes due to the long-term nature of pension and OPEB obligations and the varying market conditions likely to occur over long periods of time. As such, significant portions of pension and OPEB costs recorded in any period may not reflect the actual level of cash benefits provided to plan participants and are significantly influenced by assumptions about future market conditions and plan participants experience.

In selecting an assumed discount rate, FirstEnergy considers currently available rates of return on high-quality fixed income investments expected to be available during the period to maturity of the pension and other postretirement benefit obligations. FirstEnergy reduced its assumed discount rate as of December 31, 2003 to 6.25% from 6.75% used as of December 31, 2002.

FirstEnergy s assumed rate of return on pension plan assets considers historical market returns and economic forecasts for the types of investments held by its pension trusts. In 2003 and 2002, plan assets actually earned 24.0% and (11.3)%, respectively. FirstEnergy s pension costs in 2003 and in the first nine months of 2004 were computed assuming a 9.0% rate of return on plan assets based upon projections of future returns and its pension trust investment allocation of approximately 70% equities, 27% bonds, 2% real estate and 1% cash. In the third quarter of 2004, FirstEnergy made a $500 million voluntary contribution to its pension plan. This contribution will mitigate future funding requirements and significantly reduce the year-end minimum pension liability that currently reduces accumulated other comprehensive income by $300 million.

Health care cost trends have significantly increased and will affect future OPEB costs. The 2004 and 2003 composite health care trend rate assumptions are approximately 10%-12% gradually decreasing to 5% in later years. In determining its trend rate assumptions, FirstEnergy included the specific provisions of its health care plans, the demographics and utilization rates of plan participants, actual cost increases experienced in its health care plans, and projections of future medical trend rates.

Ohio Transition Cost Amortization

In connection with FirstEnergy s initial transition plan, the PUCO determined allowable transition costs based on amounts recorded on the regulatory books of the Ohio electric utilities. These costs exceeded those deferred or capitalized on FirstEnergy s balance sheet prepared under GAAP since they included certain costs which have not yet been incurred or that were recognized on the regulatory financial statements (fair value purchase accounting adjustments). FirstEnergy uses an effective interest method for amortizing its transition costs, often referred to as a mortgage-style amortization. The interest rate under this method is equal to the rate of return authorized by the PUCO in the Rate Stabilization Plan for each respective company. In computing the transition cost amortization, FirstEnergy includes only the portion of the transition revenues associated with transition costs included on the balance sheet prepared under GAAP. Revenues collected for the off-balance sheet costs and the return associated with these costs are recognized as income when received.

Long-Lived Assets

In accordance with SFAS 144, FirstEnergy periodically evaluates its long-lived assets to determine whether conditions exist that would indicate that the carrying value of an asset might not be fully recoverable. The accounting standard requires that if the sum of future cash flows (undiscounted) expected to result from an asset is less than the carrying value of the asset, an asset impairment must be recognized in the financial statements. If impairment has occurred, FirstEnergy recognizes a loss calculated as the difference between the carrying value and the estimated fair value of the asset (discounted future net cash flows).

The calculation of future cash flows is based on assumptions, estimates and judgment about future events. The aggregate amount of cash flows determines whether an impairment is indicated. The timing of the cash flows is critical in determining the amount of the impairment.

Nuclear Decommissioning

In accordance with SFAS 143, FirstEnergy recognizes an ARO for the future decommissioning of its nuclear power plants. The ARO liability represents an estimate of the fair value of FirstEnergy s current obligation related to nuclear decommissioning and the retirement of other assets. A fair value measurement inherently involves uncertainty in the amount and timing of settlement of the liability. FirstEnergy used an expected cash flow approach (as discussed in FCON 7) to measure the fair value of the nuclear decommissioning ARO. This approach applies probability weighting to discounted future cash flow scenarios that reflect a range of possible outcomes. The scenarios consider settlement of the ARO at the expiration of the nuclear power plants current license and settlement based on an extended license term.

Goodwill

In a business combination, the excess of the purchase price over the estimated fair values of the assets acquired and liabilities assumed is recognized as goodwill. Based on the guidance provided by SFAS 142, FirstEnergy evaluates goodwill for impairment at least annually and would make such an evaluation more frequently if indicators of impairment should arise. In accordance with the accounting standard, if the fair value of a reporting unit is less than its carrying value (including goodwill), the goodwill is tested for impairment. If an impairment is indicated, FirstEnergy recognizes a loss calculated as the difference between the implied fair value of a reporting unit s goodwill and the carrying value of the goodwill. FirstEnergy s annual review of goodwill was completed in the third quarter of 2004, with no impairment indicated. The forecasts used in FirstEnergy s evaluations of goodwill reflect operations consistent with its general business assumptions. Unanticipated changes in those assumptions could have a significant effect on FirstEnergy s future evaluations of goodwill. In the first nine months of 2004, FirstEnergy reduced goodwill by $27 million for pre-merger interest received on an income tax refund and other tax benefits. As of September 30, 2004, FirstEnergy had $6.1 billion of goodwill that primarily relates to its regulated services segment.

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NEW ACCOUNTING STANDARDS AND INTERPRETATIONS

Exposure Draft of Proposed Statement of Financial Accounting Standards Share-Based Payment an amendment of FASB Statements No. 123 and 95

In March 2004, the FASB issued an exposure draft of a new standard, which would amend SFAS 123 and SFAS 95. Among other items, the new standard would require expensing stock options in FirstEnergy s financial statements. In October 2004, the FASB agreed to delay the effective date of the proposed standard from January 1, 2005 to periods beginning after June 15, 2005, for calendar year companies. FirstEnergy will not be able to determine the impact of the proposed standard on its results of operations until the standard is issued in final form. The impact of the fair value recognition provisions of SFAS 123 on FirstEnergy s net income and earnings per share for the current reporting periods is disclosed in Note 2.

Exposure Draft of Proposed Statement of Financial Accounting Standards Earnings per Share an amendment of FASB Statement No. 128

In December 2003, the FASB issued an exposure draft of a new standard, which would amend SFAS 128. Among other items, the new standard would eliminate the provisions of SFAS 128 that allow an entity to rebut the presumption that contracts with the option of settling in either cash or stock will be settled in stock. The new standard is expected to be issued in the fourth quarter of 2004 and be effective for all periods ending after December 15, 2004. Retrospective application to all prior-period earnings per share data presented would be required. FirstEnergy is continuing to assess the proposed standard but does not anticipate a material impact on its calculation of earnings per share.

EITF Issue No. 03-1, The Meaning of Other-Than-Temporary and Its Application to Certain Investments

In March 2004, the EITF reached a consensus on the application guidance for Issue 03-1. EITF 03-1 provides a model for determining when investments in certain debt and equity securities are considered other than temporarily impaired. When an impairment is other-than-temporary, the investment must be measured at fair value and the impairment loss recognized in earnings. The recognition and measurement provisions of EITF 03-1, which were to be effective for periods beginning after June 15, 2004, were delayed by the issuance of FSP EITF 03-1-1 in September 2004. During the period of delay, FirstEnergy will continue to evaluate its investments as required by existing authoritative guidance.

EITF Issue No. 03-16, Accounting for Investments in Limited Liability Companies

In March 2004, the FASB ratified the final consensus on Issue 03-16. EITF 03-16 requires that an investment in a limited liability company that maintains a specific ownership account for each investor should be viewed as similar to an investment in a limited partnership for determining whether the cost or equity method of accounting should be used. The equity method of accounting is generally required for investments that represent more than a three to five percent interest in a limited partnership. EITF 03-16 was adopted by FirstEnergy in the third quarter of 2004 and did not affect the Companies financial statements.

FSP 106-2, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003

Issued in May 2004, FSP 106-2 provides guidance on accounting for the effects of the Medicare Act for employers that sponsor postretirement health care plans that provide prescription drug benefits. FSP 106-2 also requires certain disclosures regarding the effect of the federal subsidy provided by the Medicare Act. The effect of the federal subsidy provided under the Medicare Act on FirstEnergy s consolidated financial statements is described in Note 4. The impact of the subsidy was not material to the financial statements of each of the Companies for the three and nine months ended September 30, 2004.

FIN 46 (revised December 2003), Consolidation of Variable Interest Entities

In December 2003, the FASB issued a revised interpretation of ARB 51 referred to as FIN 46R, which requires the consolidation of a VIE by an enterprise if that enterprise is determined to be the primary beneficiary of the VIE. As required, FirstEnergy adopted FIN 46R for interests in VIEs commonly referred to as special-purpose entities effective December 31, 2003 and for all other types of entities effective March 31, 2004. Adoption of FIN 46R did not have a material impact on the consolidated financial statements of FirstEnergy or the Companies.

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OHIO EDISON COMPANY

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2004	2003	2004	2003
	(In thousands)			
STATEMENTS OF INCOME				
OPERATING REVENUES	$766,336	$774,714	$2,227,978	$2,191,165
OPERATING EXPENSES AND TAXES:				
Fuel	15,244	13,978	44,158	37,118
Purchased power	242,835	231,619	730,542	691,802
Nuclear operating costs	81,244	98,742	235,277	342,319
Other operating costs	99,132	106,802	276,289	277,402
Provision for depreciation and amortization	108,185	121,734	338,086	335,872
General taxes	47,634	46,863	135,688	139,525
Income taxes	76,502	66,453	203,863	144,533
Total operating expenses and taxes	670,776	686,191	1,963,903	1,968,571
OPERATING INCOME	95,560	88,523	264,075	222,594
OTHER INCOME	17,141	15,877	50,285	44,789
NET INTEREST CHARGES:				
Interest on long-term debt	10,657	21,241	43,641	70,686
Allowance for borrowed funds used during construction and capitalized interest	(1,950)	(1,668)	(4,924)	(4,172)
Other interest expense	640	3,416	7,576	15,219
Subsidiary s preferred stock dividend requirements	639	639	1,919	2,463
Net interest charges	9,986	23,628	48,212	84,196
INCOME BEFORE CUMULATIVE	102,715	80,772	266,148	183,187

EFFECT OF ACCOUNTING CHANGE				
Cumulative effect of accounting change (net of income taxes of $22,389,000) (Note 2)				31,720
NET INCOME	102,715	80,772	266,148	214,907
PREFERRED STOCK DIVIDEND REQUIREMENTS	623	659	1,843	1,977
EARNINGS ON COMMON STOCK	$102,092	$ 80,113	$ 264,305	$ 212,930

STATEMENTS OF COMPREHENSIVE INCOME

NET INCOME	$102,715	$ 80,772	$ 266,148	$ 214,907
OTHER COMPREHENSIVE INCOME (LOSS):				
Minimum liability for unfunded retirement benefits				(86,076)
Unrealized gain (loss) on available for sale securities	(6,913)	4,156	(2,767)	19,462
Other comprehensive income (loss)	(6,913)	4,156	(2,767)	(66,614)
Income tax related to other comprehensive income	2,850	(1,717)	1,141	27,471
Other comprehensive income (loss), net of tax	(4,063)	2,439	(1,626)	(39,143)
TOTAL COMPREHENSIVE INCOME	$ 98,652	$ 83,211	$ 264,522	$ 175,764

The preceding Notes to Consolidated Financial Statements as they relate to Ohio Edison Company are an integral part of these statements.

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OHIO EDISON COMPANY

CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2004	December 31, 2003
	(In thousands)	
ASSETS		
UTILITY PLANT:		
In service	$5,376,250	$5,269,042
Less-Accumulated provision for depreciation	2,683,177	2,578,899
	2,693,073	2,690,143
Construction work in progress-		
Electric plant	181,746	145,380
Nuclear Fuel	19,412	554
	201,158	145,934
	2,894,231	2,836,077
OTHER PROPERTY AND INVESTMENTS:		
Investment in lease obligation bonds	370,036	383,510
Certificates of deposit		277,763
Nuclear plant decommissioning trusts	410,768	376,367
Long-term notes receivable from associated companies	208,645	508,594
Other	50,298	59,102
	1,039,747	1,605,336
CURRENT ASSETS:		
Cash and cash equivalents	1,279	1,883
Receivables-		
Customers (less accumulated provisions of $8,785,000 and $8,747,000, respectively, for uncollectible accounts)	267,652	280,538
Associated companies	469,911	436,991

Other (less accumulated provisions of $563,000 and $2,282,000, respectively, for uncollectible accounts)	20,138	28,308
Notes receivable from associated companies	635,741	366,501
Materials and supplies, at average cost	88,609	79,813
Prepayments and other	16,026	14,390
	1,499,356	1,208,424
DEFERRED CHARGES:		
Regulatory assets	1,183,707	1,477,969
Property taxes	59,279	59,279
Unamortized sale and leaseback costs	61,589	65,631
Other	67,207	64,214
	1,371,782	1,667,093
	$6,805,116	$7,316,930
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION:		
Common stockholder s equity-		
Common stock, without par value, authorized 175,000,000 shares - 100 shares outstanding	$2,098,729	$2,098,729
Accumulated other comprehensive loss	(40,319)	(38,693)
Retained earnings	548,239	522,934
Total common stockholder s equity	2,606,649	2,582,970
Preferred stock not subject to mandatory redemption	60,965	60,965
Preferred stock of consolidated subsidiary not subject to mandatory redemption	39,105	39,105
Long-term debt and other long-term obligations	1,101,179	1,179,789
	3,807,898	3,862,829
CURRENT LIABILITIES:		
Currently payable long-term debt	432,406	466,589
Short-term borrowings-		
Associated companies	22,123	11,334
Other	174,010	171,540
Accounts payable-		
Associated companies	291,679	271,262
Other	9,467	7,979

Accrued taxes	213,427	560,345
Accrued interest	21,632	18,714
Other	101,138	58,680
	1,265,882	1,566,443
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	763,283	867,691
Accumulated deferred investment tax credits	65,989	75,820
Asset retirement obligation	333,644	317,702
Retirement benefits	283,548	331,829
Other	284,872	294,616
	1,731,336	1,887,658
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 3)		
	$6,805,116	$7,316,930

The preceding Notes to Consolidated Financial Statements as they relate to Ohio Edison Company are an integral part of these balance sheets.

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OHIO EDISON COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2004	2003	2004	2003
	(In thousands)			
CASH FLOWS FROM OPERATING ACTIVITIES:				
Net income	$ 102,715	$ 80,772	$ 266,148	$ 214,907
Adjustments to reconcile net income to net cash from operating activities				
Provision for depreciation and amortization	108,185	121,734	338,086	335,872
Nuclear fuel and lease amortization	11,914	10,542	33,766	28,411
Deferred income taxes, net	(7,376)	(30,010)	(50,658)	(50,714)
Investment tax credits, net	(3,998)	(3,681)	(11,303)	(11,077)
Cumulative effect of accounting change (Note 2)				(54,109)
Pension trust contribution	(72,763)		(72,763)	
Receivables	(86,506)	329,852	(10,734)	(50,930)
Materials and supplies	(2,930)	(956)	(8,796)	4,715
Deferred lease costs	33,037	33,977	30,585	31,300
Prepayments and other current assets	4,878	3,514	(1,636)	(6,285)
Accounts payable	115,690	(141,910)	21,905	113,508
Accrued taxes	(4,464)	131,470	(346,918)	180,604
Accrued interest	3,028	(417)	2,918	(5,523)
Accrued retirement benefit obligations	7,253	20,471	24,482	31,652
Accrued compensation, net	1,106	366	5,138	(8,111)
Other	(6,016)	(6,774)	(4,768)	(1,220)
Net cash provided from operating activities	203,753	548,950	215,452	753,000
CASH FLOWS FROM FINANCING ACTIVITIES:				
New Financing				
Long-term debt			30,000	575,000
Short-term borrowings, net	91,072		13,258	
Redemptions and Repayments				
Long-term debt	(36,090)	(209,111)	(152,900)	(467,567)
Short-term borrowings, net		(4,547)		(223,137)
Dividend Payments				

Common stock	(68,000)	(94,000)	(239,000)	(379,000)
Preferred stock	(623)	(659)	(1,843)	(1,977)
Net cash used for financing activities	(13,641)	(308,317)	(350,485)	(496,681)
CASH FLOWS FROM INVESTING ACTIVITIES:				
Property additions	(61,682)	(39,432)	(146,645)	(141,126)
Contributions to nuclear decommissioning trusts	(7,885)	(15,770)	(23,655)	(23,655)
Loan repayments from (loans to) associated companies, net	(378,081)	(197,289)	30,709	(146,010)
Proceeds from certificates of deposits	277,763		277,763	
Other	(20,612)	11,286	(3,743)	35,752
Net cash provided from (used for) investing activities	(190,497)	(241,205)	134,429	(275,039)
Net decrease in cash and cash equivalents	(385)	(572)	(604)	(18,720)
Cash and cash equivalents at beginning of period	1,664	2,364	1,883	20,512
Cash and cash equivalents at end of period	$ 1,279	$ 1,792	$ 1,279	$ 1,792

The preceding Notes to Consolidated Financial Statements as they relate to Ohio Edison Company are an integral part of these statements.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and Board of
Directors of Ohio Edison Company:

We have reviewed the accompanying consolidated balance sheet of Ohio Edison Company and its subsidiaries as of September 30, 2004, and the related consolidated statements of income, comprehensive income and cash flows for each of the three-month and nine-month periods ended September 30, 2004 and 2003. These interim financial statements are the responsibility of the Company s management.

We conducted our review in accordance with the standards of the Public Company Accounting Oversight Board (United States). A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the Public Company Accounting Oversight Board, the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to the accompanying consolidated interim financial statements for them to be in conformity with accounting principles generally accepted in the United States of America.

We previously audited in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet and the consolidated statement of capitalization as of December 31, 2003, and the related consolidated statements of income, common stockholder s equity, preferred stock, cash flows and taxes for the year then ended (not presented herein), and in our report (which contained references to the Company s change in its method of accounting for asset retirement obligations as of January 1, 2003 as discussed in Note 1(F) to those consolidated financial statements and the Company s change in its method of accounting for the consolidation of variable interest entities as of December 31, 2003 as discussed in Note 6 to those consolidated financial statements) dated February 25, 2004 we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying consolidated balance sheet as of December 31, 2003, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

PricewaterhouseCoopers LLP
Cleveland, Ohio
November 2, 2004

OHIO EDISON COMPANY

MANAGEMENT S DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS AND FINANCIAL CONDITION

OE is a wholly owned electric utility subsidiary of FirstEnergy. OE and its wholly owned subsidiary, Penn, conduct business in portions of Ohio and Pennsylvania, providing regulated electric distribution services. The OE Companies also provide generation services to those customers electing to retain the OE Companies as their power supplier. The OE Companies provide power directly to wholesale customers under previously negotiated contracts, as well as to some alternative energy suppliers under OE s transition plan. The OE Companies have unbundled the price of electricity into its component elements including generation, transmission, distribution and transition charges. Power supply requirements of the OE Companies are provided by FES an affiliated company.

Results of Operations

Earnings on common stock in the third quarter of 2004 increased to $102 million from $80 million in the third quarter of 2003. For the first nine months of 2004, earnings on common stock increased to $264 million from $213 million in the same period of 2003. Earnings on common stock in the first nine months of 2003 included an after-tax credit of $32 million from the cumulative effect of an accounting change due to the adoption of SFAS 143. Income before the cumulative effect was $183 million in the first nine months of 2003. Increased earnings in both 2004 periods resulted principally from lower nuclear operating costs and reduced interest charges partially offset by higher purchased power costs compared to 2003. Lower nuclear operating costs in the third quarter and the first nine months of 2004, compared with the same periods of 2003, were due to the absence of nuclear refueling outages at the Beaver Valley Units and the Perry Plant in 2003. Lower net interest charges in the third quarter and the first nine months of 2004, compared with the same periods of 2003, were primarily due to debt redemptions. Reduced provisions for depreciation and amortization in the third quarter of 2004 and higher operating revenues in the first nine months of 2004 also contributed to increased earnings for those respective periods.

Operating revenues decreased by $8 million or 1.1% in the third quarter of 2004 from the same period of 2003. Lower revenues primarily resulted from a $13 million decrease in retail electric revenues which was partially offset by a $6 million (3.5%) increase in wholesale sales (primarily to FES) due to increased available nuclear generation. The net decrease in retail electric revenues reflected lower distribution throughput revenues and increased shopping incentive credits (reflecting an increase in the shopping credit rate in Ohio) which was partially offset by a $3 million increase in retail generation revenues. Lower kilowatt-hour sales to residential customers resulting from cooler weather which reduced air conditioning loads were partially offset by the effect of a stronger economy in OE s service area. A $4 million increase in retail generation revenues to the commercial sector reflected a 1.7 percentage points decrease in electric generation services provided by alternative suppliers as a percent of total sales deliveries in the OE Companies franchise areas. Revenues from sales to residential customers decreased by $2 million as the corresponding percentage for shopping increased by 0.9 percentage points in the third quarter of 2004. Generation revenues from industrial customers were relatively flat as the percentage of customers shopping did not change.

Operating revenues increased by $37 million (1.7%) in the first nine months of 2004 compared with the same period in 2003 primarily due to a $36 million increase in wholesale sales. Revenues from wholesale sales to FES (resulting from increased nuclear generation available for sale) increased by $48 million, and was partially offset by $11 million of lower revenues due to the expiration of a contract in July 2003. Increased retail generation revenues of $15 million in the first nine months of 2004 reflected the same trend in shopping for generation providers (an increase of 1.8 percentage points for residential customers and decreases of 0.6 and 1.8 percentage points for commercial and industrial customers, respectively). Commercial and industrial revenues increased due to higher kilowatt-hour sales and unit prices which were partially offset by lower kilowatt-hour sales to residential customers.

Revenues from distribution throughput decreased by $4 million in the third quarter of 2004, but increased $1 million in the first nine months of 2004 compared with the corresponding periods of 2003. Distribution deliveries to residential customers decreased 1.6% in the third quarter of 2004 due to weather conditions as discussed above. Revenues from distribution deliveries to residential customers decreased by $7 million in the third quarter and $4 million in the first nine months of 2004 compared to the same periods of 2003 principally reflecting lower unit prices. Higher unit prices and increased distribution deliveries to commercial customers, as a result of the improving economy, increased revenues. Lower unit prices were the primary factors in the decrease in revenues from industrial customers.

Under the Ohio transition plan, OE provides incentives to customers to encourage switching to alternative energy providers $11 million of additional credits in the third quarter and $12 million of additional credits in the first nine months of 2004 compared with the corresponding periods of 2003. These revenue reductions are deferred for future recovery under OE s transition plan and do not materially affect current period earnings.

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Changes in electric generation sales and distribution deliveries in the third quarter and first nine months of 2004 from the corresponding periods of 2003 are summarized in the following table:

Changes in KWH Sales	Three Months	Nine Months
Increase (Decrease)		
Electric Generation:		
Retail	(0.2)%	0.8%
Wholesale	8.8%	13.8%
Total Electric Generation Sales	**4.1%**	**6.7%**
Distribution Deliveries:		
Residential	(1.6)%	0.7%
Commercial	1.3%	1.9%
Industrial	(0.5)%	(0.2)%
Total Distribution Deliveries	**(0.5)%**	**0.6%**

Operating Expenses and Taxes

Total operating expenses and taxes decreased $15 million in the third quarter and $5 million in the first nine months of 2004 from the same periods last year. The following table presents changes from the prior year by expense category.

Operating Expenses and Taxes Changes	Three Months	Nine Months
Increase (Decrease)	**(In millions)**	
Fuel	$ 1	$ 7
Purchased power costs	11	39
Nuclear operating costs	(17)	(107)
Other operating costs	(8)	(1)
Total operation and maintenance expenses	**(13)**	**(62)**
Provision for depreciation and amortization	(13)	2
General taxes	1	(4)
Income taxes	10	59

Total operating expenses and taxes	**$(15)**	**$ (5)**

Higher fuel costs in the third quarter and first nine months of 2004, compared with the same periods of 2003, resulted from increased nuclear generation up 8.7% and 23.7%, respectively. Purchased power costs were higher in both periods of 2004 reflecting higher unit costs and increased kilowatt-hour purchases from nonaffiliated wholesale customers. Lower nuclear operating costs for both periods were due to the absence of refueling outages in 2004 refueling outages were performed at Beaver Valley Unit 1 (100% interest), Perry plant (35.24% interest) and Beaver Valley Unit 2 (55.62% interest) in the first, second and third quarters of 2003, respectively. The decrease in other operating costs in the third quarter and first nine months of 2004, compared to the same periods of 2003, is due to reduced labor costs and lower employee benefits expenses.

Depreciation and amortization decreased in the third quarter of 2004 compared to the same period of 2003 primarily due to higher shopping incentive deferrals ($11 million) and deferred interest on the shopping incentives (see Regulatory Matters) in the third quarter of 2004 ($3 million). The increase in depreciation and amortization in the first nine months of 2004, compared with the first nine months of 2003 was primarily due to the increased amortization of Ohio transition regulatory assets ($18 million), lower tax-related deferrals ($4 million), offset by higher shopping incentive deferrals ($12 million) and deferred interest on shopping incentives ($7 million).

General taxes decreased in the first nine months of 2004 from the same period of 2003, primarily due to a $6 million refund received on a real estate valuation settlement.

Net Interest Charges

Net interest charges continued to trend lower, decreasing by $14 million in the third quarter and $36 million in the first nine months of 2004 from the same periods last year, reflecting redemptions and refinancings since the end of the third quarter of 2003. OE s long-term debt redemptions (excluding revolving credit facility activity) totaled $105 million during the first nine months of 2004, which is expected to result in annualized savings of approximately $8 million.

Cumulative Effect of Accounting Change

Upon adoption of SFAS 143 in the first quarter of 2003, OE recorded an after-tax credit to net income of $32 million. The cumulative adjustment for unrecognized depreciation, accretion offset by the reduction in the existing decommissioning liabilities and ceasing the accounting practice of depreciating non-regulated generation assets using a cost of removal component was a $54 million increase to income, or $32 million net of income taxes.

Capital Resources and Liquidity

OE s cash requirements in 2004 for operating expenses, construction expenditures, scheduled debt maturities and preferred stock redemptions are expected to be met without increasing its net debt and preferred stock outstanding. Available borrowing capacity under short-term credit facilities will be used to manage working capital requirements. Over the next two years, OE expects to meet its contractual obligations with cash from operations. Thereafter, OE expects to use a combination of cash from operations and funds from the capital markets.

Changes in Cash Position

As of September 30, 2004, OE had $1 million of cash and cash equivalents, compared with $2 million as of December 31, 2003. The major sources of changes in these balances are summarized below.

Cash Flows From Operating Activities

Cash provided from operating activities during the third quarter and first nine months of 2004, compared with the corresponding periods in 2003, were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Operating Cash Flows	**2004**	**2003**	**2004**	**2003**
	(In millions)			
Cash earnings[1]	$ 253	$ 234	$ 636	$518
Pension trust contribution	(73)		(73)	
Working capital and other	24	315	(348)	235
Total	$ 204	$ 549	$ 215	$753

(1) Includes net income, depreciation and amortization, deferred income taxes, investment tax credits and major noncash charges.

Net cash from operating activities decreased $345 million in the third quarter of 2004 from the third quarter of 2003 due to a $291 million decrease from changes in working capital and a voluntary pension trust contribution of $73 million. These decreases were partially offset in part by a $19 million increase in cash earnings as described above under Results from Operations . The change in working capital primarily reflects an increase in accounts receivable from associated companies and a decrease in accrued tax due to higher estimated tax payments in the third quarter of 2004 compared with the third quarter of 2003. These changes were partially offset by an increase in accounts payable. Net cash from operating activities decreased $538 million in the first nine months of 2004 due to a $583 million decrease from changes in working capital and the $73 million pension contribution. These decreases were partially offset by a $118 million increase in cash earnings. The change in working capital primarily reflects lower accounts payable and accrued taxes, reflecting changes of $249 million for the reallocation of tax liabilities between associated companies related to the tax sharing agreement.

Cash Flows From Financing Activities

In the third quarter of 2004, net cash used for financing activities was $14 million compared to $308 million in the third quarter of 2003. The change resulted from a $173 million decrease in net debt redemptions, a $96 million net increase in short-term borrowings and a $26 million decrease in common stock dividend payments to FirstEnergy. In the first nine months of 2004, net cash used for financing activities decreased to $350 million from $496 million in the same period last year. The decrease resulted from reduced payments on short-term borrowings of $236 million and $140 million of reduced common stock dividends to FirstEnergy, partially offset by $230 million of reduced financings in 2004.

On June 7, 2004, OE replaced certain collateralized LOCs that were issued in 1994 in support of OE s obligations to lessors under the Beaver Valley Unit 2 sale and leaseback arrangements. Approximately $289 million in cash collateral and accrued interest previously held by OES Finance Incorporated, a wholly owned subsidiary of OE, was released on July 15, 2004 upon cancellation of the existing LOCs and was used to repay short-term debt and for other corporate purposes. Simultaneously with the issuance of the replacement LOCs, OE entered into a Credit Agreement pursuant to which a standby LOC was issued in support of the replacement LOCs, and the issuer of the LOCs obtained the right to pledge or assign participations in OE s reimbursement obligations to a trust. The trust then issued and sold trust certificates to institutional investors that were designed to be the credit equivalent of an investment directly in OE.

OE had approximately $637 million of cash and temporary investments (which include short-term notes receivable from associated companies) and approximately $196 million of short-term indebtedness as of September 30, 2004. Available borrowing capability under bilateral bank facilities totaled $14 million as of September 30, 2004. OE has obtained authorization from the PUCO to incur short-term debt of up to $500 million (including bank facilities and the utility money pool described below). Penn has obtained authorization from the SEC to incur short-term debt up to its charter limit of $46 million (including the utility money pool). OE and Penn had the capability to issue $1.6 billion and $497 million, respectively, of additional FMB on the basis of property additions and retired bonds under the terms of their respective mortgage indentures. The issuance of FMB by OE is subject to a provision of its senior note indenture generally limiting the incurrence of additional secured debt, subject to certain exceptions that would permit, among other things, the issuance of secured debt (including FMB) (i) supporting pollution control notes or similar obligations, or (ii) as an extension, renewal or replacement of previously outstanding secured debt. In addition, this provision would permit OE to incur additional secured debt not otherwise permitted by a specified exception of up to $639 million as of September 30, 2004. Based upon applicable earnings coverage tests, the OE Companies could issue up to $3.1 billion of preferred stock (assuming no additional debt was issued) as of September 30, 2004.

OE s $125 million 364-day revolving credit facility was restructured through a new syndicated FirstEnergy facility that was completed on June 22, 2004. Combined with an existing syndicated $125 million three-year facility for OE maturing in October 2006, an existing syndicated $250 million two-year facility for OE maturing in May 2005 and bank facilities of $34 million, OE s credit facilities total $409 million, of which $389 million was unused as of September 30, 2004. These facilities are intended to provide liquidity to meet the short-term working capital requirements of OE and its regulated affiliates.

Borrowings under these facilities are conditioned on OE maintaining compliance with certain financial covenants. OE, under its $125 million 364-day and $250 million two-year facilities, is required to maintain a debt to total capitalization ratio of no more than 0.65 to 1 and a contractually-defined fixed charge coverage ratio of no less than 2 to 1. OE is in compliance with these financial covenants. As of September 30, 2004, OE s fixed charge coverage ratio, as defined under the credit agreements, was 7.36 to 1. OE s debt to total capitalization ratio, as defined under the credit agreements, was 0.39 to 1. The ability to draw on these facilities is also conditioned upon OE making certain representations and warranties to the lending banks prior to drawing on its facilities, including a representation that there has been no material adverse change in its business, its condition (financial or otherwise), its results of operations, or its prospects.

OE s primary credit facilities contain no provisions restricting its ability to borrow, or accelerating repayment of outstanding loans, as a result of any change in its S&P or Moody s credit ratings. The primary facilities do contain pricing grids , whereby the cost of funds borrowed under the facilities is related to the credit ratings of the company borrowing the funds.

OE has the ability to borrow from its regulated affiliates and FirstEnergy to meet its short-term working capital requirements. FESC administers this money pool and tracks surplus funds of FirstEnergy and its regulated subsidiaries, as well as proceeds available from bank borrowings. Available bank borrowings include $1.75 billion from FirstEnergy s and OE s revolving credit facilities. Companies receiving a loan under the money pool agreements must repay the principal amount of such a loan, together with accrued interest, within 364 days of borrowing the funds. The rate of interest is the same for each company receiving a loan from the pool and is based on the average cost of funds available through the pool. The average interest rate for borrowings in the third quarter of 2004 was

1.28%.

In March 2004, Penn completed a receivables financing arrangement that provides borrowing capability of up to $25 million. The borrowing rate is based on bank commercial paper rates. Penn is required to pay an annual facility fee of 0.40% on the entire finance limit. The facility was undrawn as of September 30, 2004 and matures on March 29, 2005.

OE s access to capital markets and costs of financing are dependent on the ratings of its securities and the securities of FirstEnergy. The ratings outlook on all such securities is stable.

On July 22, 2004, S&P updated its analysis of U.S. utility FMBs in response to changes in the industry. As a result of its revised methodology for evaluating default risk, S&P raised its FMB credit ratings for 20 U.S. utility companies, including Penn. Penn s FMB credit rating was upgraded to BBB from BBB-.

On August 26, 2004, S&P stated that a favorable outcome of the Ohio Rate Stabilization Plan auction process and a favorable resolution of pending environmental litigation would support a higher ratings outlook, or possibly a higher rating. S&P noted that a ratings upgrade in 2004 does not appear likely because those major issues would most likely not be resolved before the end of 2004. On September 14, 2004, S&P stated that FirstEnergy s $500 million voluntary contribution to its pension plan was credit neutral.

Cash Flows From Investing Activities

Net cash used for investing activities totaled $190 million in the third quarter of 2004 and $134 million provided from investing activities for the first nine months of 2004, compared to net cash used for investing activities of $241 million and $275 million, respectively, for the same periods of 2003. The $51 million change for the third quarter and $409 million for the first nine months, resulted primarily from $278 million of cash proceeds from certificates of deposit in the third quarter of 2004. Loans to associated companies increased $181 million in the third quarter of 2004 and decreased $177 million first nine months, compared to the same periods in 2003.

During the last quarter of 2004, capital requirements for property additions and capital leases are expected to be about $78 million, including $29 million for nuclear fuel. OE has additional requirements of approximately $18 million to meet sinking fund requirements for preferred stock and maturing long-term debt during the remainder of 2004. Those requirements are expected to be satisfied from internal cash and short-term credit arrangements.

Off-Balance Sheet Arrangements

Obligations not included on OE s Consolidated Balance Sheet primarily consist of sale and leaseback arrangements involving Perry Unit 1 and Beaver Valley Unit 2. As of September 30, 2004, the present value of these sale and leaseback operating lease commitments, net of trust investments, total $696 million.

Equity Price Risk

Included in OE s nuclear decommissioning trust investments are marketable equity securities carried at their market value of approximately $227 million and $209 million as of September 30, 2004 and December 31, 2003, respectively. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $23 million reduction in fair value as of September 30, 2004.

Outlook

Beginning in 2001, OE s customers were able to select alternative energy suppliers. OE continues to deliver power to residential homes and businesses through its existing distribution system, which remains regulated. Customer rates have been restructured into separate components to support customer choice. In Ohio and Pennsylvania, the OE Companies have a continuing responsibility to provide power to those customers not choosing to receive power from an alternative energy supplier subject to certain limits. Adopting new approaches to regulation and experiencing new forms of competition have created new uncertainties.

Regulatory Matters

Beginning on January 1, 2001, OE s customers were able to choose their electricity suppliers. Customer rates were restructured to establish separate charges for transmission, distribution, transition cost recovery and a generation-related component. When one of OE s customers elects to obtain power from an alternative supplier, OE reduces the customer s bill with a generation shopping credit, based on the regulated generation component (plus an incentive), and the customer receives a generation charge from the alternative supplier. Under the recently approved Rate Stabilization Plan, OE has continuing PLR responsibility to its franchise customers through December 31, 2008.

As part of OE s transition plan, it is obligated to supply electricity to customers who do not choose an alternative supplier. OE is also required to provide 560 MW of low cost supply to unaffiliated alternative suppliers who serve customers within its service area. FES acts as an alternate supplier for a portion of the load in OE s franchise area.

On October 21, 2003, the Ohio Companies filed an application with the PUCO to establish generation service rates beginning January 1, 2006, in response to expressed concerns by the PUCO about price and supply uncertainty following the end of the market development period. The filing included two options:

A competitive auction, which would establish a price for generation that customers would be charged during the period covered by the auction, or

A Rate Stabilization Plan, which would extend current generation prices through 2008, ensuring adequate generation supply at stable prices, and continuing OE s support of energy efficiency and economic development efforts.

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Under that proposal, OE requested:

- Extension of the transition cost amortization period for OE from 2006 to 2007;
- Deferral of interest costs on the accumulated shopping incentives and other cost deferrals as new regulatory assets; and
- Ability to initiate a request to increase generation rates under certain limited conditions.

On February 23, 2004, after consideration of the PUCO Staff comments and testimony as well as those provided by some of the intervening parties, OE made certain modifications to the Rate Stabilization Plan. On June 9, 2004, the PUCO issued an order approving the revised Rate Stabilization Plan, subject to conducting a competitive bid process on or before December 1, 2004. In addition to requiring the competitive bid process, the PUCO made other modifications to OE s revised Rate Stabilization Plan application. Among the major modifications were the following:

- Limiting OE s ability to request adjustments in generation charges during 2006 through 2008 to increases in taxes;
- Expanding the availability of market support generation;
- Revising the kilowatt-hour target level and the time period for recovering regulatory transition charges;
- Establishing a 3-year competitive bid process for generation;
- Establishing the 2005 generation credit for shopping customers, which would be extended as a cap through 2008; and
- Denying the ability to defer costs for future recovery of distribution reliability improvement expenditures.

On June 18, 2004, OE filed with the PUCO an application for rehearing of the modified version of the Rate Stabilization Plan. Several other parties also filed applications for rehearing. On August 4, 2004, the PUCO issued an Entry on Rehearing modifying its June 9, 2004 Order. The modifications included the following:

- Expanding OE s ability to request adjustments in generation charges during 2006 through 2008 to include increases in the cost of fuel (including the cost of emission allowances consumed, lime, stabilizers and other additives and fuel disposal) using 2002 as the base year. Any increases in fuel costs would be subject to downward adjustments in subsequent years should fuel costs decline, but not below the generation rate initially established in the Rate Stabilization Plan;
- Approving the revised kilowatt-hour target level and time period for recovery of regulatory transition costs as presented by OE in its rehearing application;
- Retaining the requirement for expanded availability of market support generation, but adopting OE s alternative approach that conditions expanded availability on higher pricing and eliminating the requirement to reduce the interest deferral for certain affected rate schedules;
- Revising the calculation of the shopping credit cap for certain commercial and small industrial rate schedules; and
- Relaxing the notice requirement for availability of enhanced shopping credits in a number of instances.

On August 5, 2004, OE accepted the Rate Stabilization Plan as modified and approved by the PUCO on August 4, 2004. OE retains the right to withdraw the modified Rate Stabilization Plan should subsequent adverse action be taken by the PUCO or a court. In the second quarter of 2004, OE implemented the accounting modifications contained in the PUCO s June 9, 2004 Order, which are consistent with the PUCO s August 4, 2004 Entry on Rehearing. Those modifications included amortization of transition costs based on extended amortization periods (that are no later than 2007 for OE) and the deferral of interest costs on the accumulated deferred shopping incentives. On October 1, 2004, the OCC filed an appeal with the Ohio Supreme Court to overturn the June 9, 2004 PUCO order.

OE filed a proposed competitive bid process which the PUCO modified on October 6, 2004. The PUCO approved the rules for the competitive bid process setting a three-year supply period (2006-2008) requirement for generation service suppliers and a load cap for individual suppliers. In mid-October, the initial auction schedule was revised so that Part 1 and Part 2 auction bidder applications are due November 4 and November 15, 2004, respectively; the trial auction is scheduled to occur on December 3; the auction would commence December 8 and the PUCO will accept or reject the auction results within two business days after the completion of the auction. FirstEnergy has elected not to participate in the auction.

Regulatory Assets

Regulatory assets are costs which have been authorized by the PUCO, PPUC and the FERC, for recovery from customers in future periods and, without such authorization, would have been charged to income when incurred. The OE Companies regulatory assets are expected to continue to be recovered under the provisions of their respective transition plan and rate restructuring plans. The OE Companies regulatory assets were as follows:

Regulatory Assets as of

	September 30, 2004	December 31, 2003
	(In millions)	
Company		
OE	$1,184	$1,450
Penn	*	28
Consolidated Total	$1,184	$1,478

* Changes in Penn s net regulatory asset components through September 30, 2004 resulted in net regulatory liabilities of approximately $4 million included in Other Noncurrent Liabilities on the Consolidated Balance Sheet as of September 30, 2004.

Reliability Initiatives

On October 15, 2003, NERC issued a letter to all NERC control areas and reliability coordinators requesting a review of various reliability practices. The Company response confirmed that its review was completed and that various enhancements were underway to current practices. On February 10, 2004, NERC issued its Recommended Actions to Prevent and Mitigate the Impacts of Future Cascading Blackouts, a portion of which were directed at the FirstEnergy companies and broadly focused on initiatives that were recommended for completion by June 30, 2004. FirstEnergy s detailed implementation plan was endorsed by the NERC Board of Trustees on May 7, 2004. The various initiatives recommended by NERC were certified as complete by June 30, 2004, with one minor exception related to reactive testing of certain generators expected to be completed later in 2004.

On February 26 and 27, 2004, OE, as part of a NERC review of control area operations throughout the United States, participated in a NERC Control Area Readiness Audit. The final audit report, completed on May 6, 2004, identified positive observations and included various recommendations for reliability improvement. FirstEnergy reported completion of those recommendations on June 30, 2004, with one exception related to MISO s implementation of a voltage stability tool expected to be completed later this year.

On April 5, 2004, the U.S. Canada Power System Outage Task Force issued a Final Report on the August 14, 2003 power outages. The Final Report contains 46 recommendations to prevent or minimize the scope of future blackouts. Forty-five of those recommendations relate to broad industry or policy matters while one relates to activities the Task Force recommended be undertaken by FirstEnergy, MISO, PJM and ECAR. FirstEnergy completed the Task Force recommendations that were directed toward FirstEnergy and reported completion of those activities on June 30, 2004.

With respect to each of the foregoing initiatives, FirstEnergy requested and NERC provided, a technical assistance team of experts to provide ongoing guidance and assistance in implementing and confirming timely and successful completion. NERC further assembled an independent verification team to confirm implementation of the foregoing initiatives required to be completed as of June 30, 2004. The NERC Verification Team reported, on July 14, 2004, that FirstEnergy has completed the recommended policies, procedures and actions required to be completed by June 30, 2004 or summer 2004, with exceptions noted by FirstEnergy. Implementation of the recommendations has not required incremental material investment or upgrades to existing equipment.

On March 1, 2004, OE filed, in accordance with a November 25, 2003 order from the PUCO, their plan for addressing certain issues identified by the PUCO from the U.S. Canada Power System Outage Task Force interim report. In particular, the filing addressed upgrades to FirstEnergy s control room computer hardware and software and enhancements to the training of control room operators. The PUCO will review the plan before determining the next steps, if any, in the proceeding.

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On April 22, 2004, FirstEnergy filed with the FERC the results of the FERC-ordered independent study of part of Ohio s power grid. The study examined, among other things, the reliability of the transmission grid in critical points in the Northern Ohio area and the need, if any, for reactive power reinforcements during summers 2004 and 2009. Certain requested additional clarifications were provided to the FERC in October 2004. FirstEnergy completed the implementation of recommendations relating to 2004 by June 30, 2004, and is continuing to review results related to 2009. The estimated capital expenditures required by 2009 are not expected to have a material adverse effect on FirstEnergy s financial results. FirstEnergy notes, however, that FERC or other applicable government agencies and reliability coordinators may take a different view as to recommended enhancements or may recommend additional enhancements in the future that could require additional, material expenditures.

In late 2003, the PPUC issued a Tentative Order implementing new reliability benchmarks and standards. In connection therewith, the PPUC commenced a rulemaking procedure to amend the Electric Service Reliability Regulations to implement these new benchmarks, and required additional reporting on reliability. The PPUC ordered all Pennsylvania utilities to begin filing quarterly reports on November 1, 2003. On May 11, 2004, the PPUC issued an order approving the revised reliability benchmark and standards, including revised benchmarks and standards for Met-Ed, Penelec and Penn. The Order permitted Pennsylvania utilities to file in a separate proceeding to revise the recomputed benchmarks and standards if they have evidence, such as the impact of automated outage management systems, on the accuracy of the PPUC computed reliability indices. Penn filed a Petition for Amendment of Benchmarks with the PPUC on May 26, 2004 seeking amendment of the benchmarks and standards due to their implementation of automated outage management systems following restructuring. No procedural schedule or hearing date has been set for this proceeding. Penn is unable to predict the outcome of this proceeding.

On January 16, 2004, the PPUC initiated a formal investigation of whether Penn s service reliability performance deteriorated to a point below the level of service reliability that existed prior to restructuring in Pennsylvania. Hearings were held in early August 2004. On September 30, 2004, Penn filed a settlement agreement with the PPUC that addresses the issues related to this investigation. As part of the settlement, Penn agreed to enhance service reliability, performance reporting and communications with customers and together with Met-Ed and Penelec, to collectively maintain their current spending levels of at least $255 million annually on combined capital and operation and maintenance expenditures for transmission and distribution for the years 2005 through 2007. In November 2004, the PPUC accepted the recommendation of the ALJ approving the settlement.

Environmental Matters

Various federal, state and local authorities regulate OE with regard to air and water quality and other environmental matters. The effects of compliance on OE with regard to environmental matters could have a material adverse effect on its earnings and competitive position. These environmental regulations affect OE s earnings and competitive position to the extent that it competes with companies that are not subject to such regulations and therefore do not bear the risk of costs associated with compliance, or failure to comply, with such regulations. Overall, OE believes it is in material compliance with existing regulations but is unable to predict future change in regulatory policies and what, if any, the effects of such change would be.

OE is required to meet federally approved SO_2 regulations. Violations of such regulations can result in shutdown of the generating unit involved and/or civil or criminal penalties of up to $31,500 for each day the unit is in violation. The EPA has an interim enforcement policy for SO_2 regulations in Ohio that allows for compliance based on a 30-day averaging period. OE cannot predict what action the EPA may take in the future with respect to the interim enforcement policy.

In 1999 and 2000, the EPA issued NOV or a Compliance Orders to nine utilities covering 44 power plants, including the W. H. Sammis Plant. In addition, the U.S. Department of Justice filed eight civil complaints against various investor-owned utilities, which included a complaint against OE and Penn in the U.S. District Court for the Southern District of Ohio. These cases are referred to as New Source Review cases. The NOV and complaint allege violations of the Clean Air Act based on operation and maintenance of the W. H. Sammis Plant dating back to 1984. The complaint requests permanent injunctive relief to require the installation of best available control technology and civil penalties of up to $27,500 per day of violation. On August 7, 2003, the United States District Court for the Southern District of Ohio ruled that 11 projects undertaken at the W. H. Sammis Plant between 1984 and 1998 required pre-construction permits under the Clean Air Act. The ruling concludes the liability phase of the case, which deals with applicability of Prevention of Significant Deterioration provisions of the Clean Air Act. The remedy phase trial to address civil penalties and what, if any, actions should be taken to further reduce emissions at the plant has been rescheduled to January 2005 by the Court because the parties are engaged in meaningful settlement negotiations. The Court indicated, in its August 2003 ruling, that the remedies it may consider and impose involved a much broader, equitable analysis, requiring the Court to consider air quality, public health, economic impact, and employment consequences. The Court may also consider the less than consistent efforts of the EPA to apply and further enforce the Clean Air Act. The potential penalties that may be imposed, as well as the capital expenditures necessary to comply with substantive remedial measures that may be

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required, could have a material adverse impact on the OE Companies financial condition and results of operations. While the parties are engaged in meaningful settlement discussions, management is unable to predict the ultimate outcome of this matter and no liability has been accrued as of September 30, 2004.

The OE Companies believe they are complying with SO_2 reduction requirements under the Clean Air Act Amendments of 1990 by burning lower-sulfur fuel, generating more electricity from lower-emitting plants, and/or using emission allowances. NO_x reductions required by the 1990 Amendments are being achieved through combustion controls and the generation of more electricity at lower-emitting plants. In September 1998, the EPA finalized regulations requiring additional NO_x reductions from the OE Companies facilities. The EPA s NO_x Transport Rule imposes uniform reductions of NO_x emissions (an approximate 85% reduction in utility plant NO_x emissions from projected 2007 emissions) across a region of nineteen states (including Michigan, New Jersey, Ohio and Pennsylvania) and the District of Columbia based on a conclusion that such NO_x emissions are contributing significantly to ozone levels in the eastern United States. SIPs were required to comply by May 31, 2004 with individual state NO_x budgets. Pennsylvania submitted a SIP that required compliance with the state NO_x budgets at the OE Companies Pennsylvania facilities by May 1, 2003. Ohio submitted a SIP that requires required compliance with the state NO_x budgets at the OE Companies Ohio facilities by May 31, 2004. The OE Companies believe their facilities are complying with the state NO_x budgets through combustion controls and post-combustion controls, including Selective Catalytic Reduction and Selective Non-Catalytic Reduction systems, and/or using emission allowances.

On September 7, 2004, the EPA established new performance standards under Clean Water Act Section 316(b) for reducing impacts on fish and shellfish from cooling water intake structures at certain existing large electric generating plants. The regulations call for reductions in impingement mortality, when aquatic organisms are pinned against screens or other parts of a cooling water intake system and entrainment, which occurs when aquatic species are drawn into a facility s cooling water system. The OE Companies are conducting comprehensive demonstration studies, due in 2008, to determine the operational measures, equipment or restoration activities, if any, necessary for compliance by their facilities with the performance standards. The OE Companies are unable to predict the outcome of such studies. Depending on the outcome of such studies, the future cost of compliance with these standards may be substantial.

Power Outages and Related Litigation

On August 14, 2003, various states and parts of southern Canada experienced widespread power outages. The outages affected approximately 1.4 million customers in FirstEnergy s service area. On April 5, 2004, the U.S. Canada Power System Outage Task Force released its final report on the outages. In the final report, the Task Force concluded, among other things, that the problems leading to the outages began in FirstEnergy s Ohio service area. Specifically, the final report concludes, among other things, that the initiation of the August 14, 2003 power outages resulted from an alleged failure of both FirstEnergy and ECAR to assess and understand perceived inadequacies within the FirstEnergy system; inadequate situational awareness of the developing conditions; and a perceived failure to adequately manage tree growth in certain transmission rights of way. The Task Force also concluded that there was a failure of the interconnected grid s reliability organizations (MISO and PJM) to provide effective diagnostic support. The final report is publicly available through the Department of Energy s website (www.doe.gov). FirstEnergy believes that the final report does not provide a complete and comprehensive picture of the conditions that contributed to the August 14, 2003 power outages and that it does not adequately address the underlying causes of the outages. FirstEnergy remains convinced that the outages cannot be explained by events on any one utility s system. The final report contains 46 recommendations to prevent or minimize the scope of future blackouts. Forty-five of those recommendations relate to broad industry or policy matters while one, including subparts, relates to activities the Task Force recommends be undertaken by FirstEnergy, MISO, PJM, and ECAR. FirstEnergy implemented several initiatives, both prior to and since the August 14, 2003 power outages, which are consistent with these and other recommendations and collectively enhance the reliability of its electric system. FirstEnergy certified to NERC on June 30, 2004, completion of various reliability recommendations and further received independent verification of completion status from a NERC verification team on July 14, 2004 (see Reliability initiatives above). FirstEnergy s implementation of these recommendations included completion of the Task Force recommendations that were directed toward FirstEnergy. As many of these initiatives already were in process and budgeted in 2004, FirstEnergy does not believe that any incremental expenses associated with additional initiatives undertaken during 2004 will have a material effect on its operations or financial results. FirstEnergy notes, however, that the applicable government agencies and reliability coordinators may take a different view as to recommended enhancements or may recommend additional enhancements in the future that could require additional, material expenditures. FirstEnergy has not accrued a liability as of September 30, 2004 for any expenditures in excess of those actually incurred through that date.

Three substantially similar actions were filed in various Ohio state courts by plaintiffs seeking to represent customers who allegedly suffered damages as a result of the August 14, 2003 power outages. All three cases were dismissed for lack of jurisdiction. One case was refiled at the PUCO and the other two have been appealed. In addition to the one case that was refiled at the PUCO, the Ohio Companies were named as respondents in a regulatory proceeding that was initiated at the PUCO in response to complaints alleging failure to provide reasonable and adequate service stemming primarily from the August 14, 2003 power outages.

One complaint has been filed against FirstEnergy in the New York State Supreme Court. In this case, several plaintiffs in the New York City metropolitan area allege that they suffered damages as a result of the August 14, 2003 power outages. None of the plaintiffs are customers of any FirstEnergy affiliate. FirstEnergy filed a motion to dismiss with the Court on October 22, 2004. No damage estimate has been provided and thus potential liability has not been determined.

FirstEnergy is vigorously defending these actions, but cannot predict the outcome of any of these proceedings or whether any further regulatory proceedings or legal actions may be instituted against the Companies. In particular, if FirstEnergy or its subsidiaries were ultimately determined to have legal liability in connection with these proceedings, it could have a material adverse effect on FirstEnergy s or its subsidiaries financial condition and results of operations.

Legal Matters

Various lawsuits, claims (including claims for asbestos exposure) and proceedings related to OE s normal business operations are pending against OE and its subsidiaries. The most significant not otherwise discussed above are described below.

On August 12, 2004, the NRC publicly disclosed that it was notifying FirstEnergy that it will increase its regulatory oversight of the Perry Nuclear Power Plant as a result of problems with safety system equipment over the past two years. The OE Companies have a 35.24% interest in the Perry Nuclear Power Plant. The NRC noted that the plant continues to operate safely. The increased oversight will include an extensive NRC team inspection to access the equipment problems and FirstEnergy s corrective actions. The outcome of this increased oversight is not known at this time.

On October 20, 2004, FirstEnergy was notified by the SEC that the previously disclosed informal inquiry initiated by the SEC s Division of Enforcement in September 2003 relating to the restatements in August 2003 of previously reported results by FirstEnergy and OE and the Davis-Besse extended outage (OE has no interest in Davis-Besse) has become the subject of a formal order of investigation. The SEC s formal order of investigation also encompasses issues raised during the SEC s examination of FirstEnergy and the Companies under the PUHCA. Concurrent with this notification, FirstEnergy received a subpoena asking for background documents and documents related to the restatements and Davis-Besse issues. FirstEnergy has cooperated fully with the informal inquiry and will continue to do so with the formal investigation.

If it were ultimately determined that FirstEnergy or its subsidiaries has legal liability or is otherwise made subject to liability based on any of the above matters, it could have a material adverse effect on FirstEnergy s or its subsidiaries financial condition and results of operations.

Critical Accounting Policies

OE prepares its consolidated financial statements in accordance with GAAP. Application of these principles often requires a high degree of judgment, estimates and assumptions that affect financial results. All of the OE Companies assets are subject to their own specific risks and uncertainties and are regularly reviewed for impairment. Assets related to the application of the policies discussed below are similarly reviewed with their risks and uncertainties reflecting these specific factors. The OE Companies more significant accounting policies are described below.

Regulatory Accounting

The OE Companies are subject to regulation that sets the prices (rates) they are permitted to charge their customers based on costs that the regulatory agencies determine the OE Companies are permitted to recover. At times, regulators permit the future recovery through rates of costs that would be currently charged to expense by an unregulated company. This rate-making process results in the recording of regulatory assets based on anticipated future cash inflows. OE regularly reviews these assets to assess their ultimate recoverability within the approved regulatory guidelines. Impairment risk associated with these assets relates to potentially adverse legislative, judicial or regulatory actions in the future.

Revenue Recognition

The OE Companies follow the accrual method of accounting for revenues, recognizing revenue for electricity that has been delivered to customers but not yet billed through the end of the accounting period. The determination of electricity sales to individual customers is based on meter readings, which occur on a systematic basis throughout the month. At the end of each month, electricity delivered to customers since the last meter reading is estimated and a corresponding accrual for unbilled revenues is recognized. The determination of unbilled revenues requires management to make estimates regarding electricity available for retail load, transmission and distribution line losses, demand by customer class, weather-related impacts and electricity provided by alternative suppliers.

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Pension and Other Postretirement Benefits Accounting

FirstEnergy s pension and postretirement benefit obligations are allocated to its subsidiaries employing the plan participants. Employee benefits related to construction projects are capitalized. OE s reported costs of providing non-contributory defined pension benefits and postemployment benefits other than pensions are dependent upon numerous factors resulting from actual plan experience and certain assumptions.

Pension and OPEB costs are affected by employee demographics (including age, compensation levels and employment periods), the level of contributions to the plans, and earnings on plan assets. Such factors may be further affected by business combinations (such as FirstEnergy s merger with GPU in November 2001), which impacts employee demographics, plan experience and other factors. Pension and OPEB costs are also affected by changes to key assumptions, including anticipated rates of return on plan assets, the discount rates and health care trend rates used in determining the projected benefit obligations for pension and OPEB costs.

In accordance with SFAS 87 and SFAS 106, changes in pension and OPEB obligations associated with these factors may not be immediately recognized as costs on the income statement, but generally are recognized in future years over the remaining average service period of plan participants. SFAS 87 and SFAS 106 delay recognition of changes due to the long-term nature of pension and OPEB obligations and the varying market conditions likely to occur over long periods of time. As such, significant portions of pension and OPEB costs recorded in any period may not reflect the actual level of cash benefits provided to plan participants and are significantly influenced by assumptions about future market conditions and plan participants experience.

In selecting an assumed discount rate, FirstEnergy considers currently available rates of return on high-quality fixed income investments expected to be available during the period to maturity of the pension and other postretirement benefit obligations. FirstEnergy reduced its assumed discount rate as of December 31, 2003 to 6.25% from 6.75% used as of December 31, 2002.

FirstEnergy s assumed rate of return on pension plan assets considers historical market returns and economic forecasts for the types of investments held by its pension trusts. In 2003 and 2002, plan assets actually earned 24.0% and (11.3)%, respectively. FirstEnergy s pension costs in 2003 and in the first nine months of 2004 were computed assuming a 9.0% rate of return on plan assets based upon projections of future returns and its pension trust investment allocation of approximately 70% equities, 27% bonds, 2% real estate and 1% cash. In the third quarter of 2004, FirstEnergy made a $500 million voluntary contribution to its pension plan ($73 million funded by the OE Companies). This contribution will mitigate future funding requirements and significantly reduce the year-end minimum pension liability that currently reduces the OE Companies accumulated other comprehensive income by $62 million.

Health care cost trends have significantly increased and will affect future OPEB costs. The 2004 and 2003 composite health care trend rate assumptions are approximately 10%-12% gradually decreasing to 5% in later years. In determining its trend rate assumptions, FirstEnergy included the specific provisions of its health care plans, the demographics and utilization rates of plan participants, actual cost increases experienced in its health care plans, and projections of future medical trend rates.

Ohio Transition Cost Amortization

In connection with FirstEnergy s initial transition plan, the PUCO determined allowable transition costs based on amounts recorded on OE s regulatory books. These costs exceeded those deferred or capitalized on OE s balance sheet prepared under GAAP since they included certain costs which have not yet been incurred. OE uses an effective interest method for amortizing its transition costs, often referred to as a mortgage-style amortization. The interest rate under this method is equal to the rate of return authorized by the PUCO in the Rate Stabilization Plan for OE. In computing the transition cost amortization, OE includes only the portion of the transition revenues associated with transition costs included on the balance sheet prepared under GAAP. Revenues collected for the off-balance sheet costs and the return associated with these costs are recognized as income when received.

Long-Lived Assets

In accordance with SFAS 144, the OE Companies periodically evaluate their long-lived assets to determine whether conditions exist that would indicate that the carrying value of an asset might not be fully recoverable. The accounting standard requires that if the sum of future cash flows (undiscounted) expected to result from an asset is less than the carrying value of the asset, an asset impairment must be recognized in the financial statements. If impairment has occurred, the OE Companies recognize a loss calculated as the difference between the carrying value and the estimated fair value of the asset (discounted future net cash flows).

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The calculation of future cash flows is based on assumptions, estimates and judgment about future events. The aggregate amount of cash flows determines whether an impairment is indicated. The timing of the cash flows is critical in determining the amount of the impairment.

Nuclear Decommissioning

In accordance with SFAS 143, the OE Companies recognize an ARO for the future decommissioning of their nuclear power plants. The ARO represents an estimate of the fair value of the OE Companies current obligation related to nuclear decommissioning and the retirement of other assets. A fair value measurement inherently involves uncertainty in the amount and timing of settlement of the liability. The OE Companies used an expected cash flow approach (as discussed in FCON 7) to measure the fair value of the nuclear decommissioning ARO. This approach applies probability weighting to discounted future cash flow scenarios that reflect a range of possible outcomes. The scenarios consider settlement of the ARO at the expiration of the nuclear power plants current license and settlement based on an extended license term.

New Accounting Standards And Interpretations

EITF Issue No. 03-1, The Meaning of Other-Than-Temporary and Its Application to Certain Investments

In March 2004, the EITF reached a consensus on the application guidance for Issue 03-1. EITF 03-1 provides a model for determining when investments in certain debt and equity securities are considered other than temporarily impaired. When an impairment is other-than-temporary, the investment must be measured at fair value and the impairment loss recognized in earnings. The recognition and measurement provisions of EITF 03-1, which were to be effective for periods beginning after June 15, 2004, were delayed by the issuance of FSP EITF 03-1-1 in September 2004. During the period of delay, OE will continue to evaluate its investments as required by existing authoritative guidance.

FSP 106-2, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003

Issued in May 2004, FSP 106-2 provides guidance on the accounting for the effects of the Medicare Act for employers that sponsor postretirement health care plans that provide prescription drug benefits. FSP 106-2 also requires certain disclosures regarding the effect of the federal subsidy provided by the Medicare Act. See Note 4 for a discussion of the effect of the federal subsidy provided under the Medicare Act on the consolidated financial statements.

FIN 46 (revised December 2003), Consolidation of Variable Interest Entities

In December 2003, the FASB issued a revised interpretation of ARB 51, referred to as FIN 46R, which requires the consolidation of a VIE by an enterprise if that enterprise is determined to be the primary beneficiary of the VIE. As required, OE adopted FIN 46R for interests in VIEs commonly referred to as special-purpose entities effective December 31, 2003 and for all other types of entities effective March 31, 2004. Adoption of FIN 46R did not have a material impact on OE s consolidated financial statements. See Note 2 Consolidation for a discussion of variable interest entities.

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THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2004	**2003**	**2004**	**2003**
	(In thousands)			
STATEMENTS OF INCOME				
OPERATING REVENUES	$504,848	$496,110	$1,372,259	$1,328,014
OPERATING EXPENSES AND TAXES:				
Fuel	21,011	5,536	57,583	30,117
Purchased power	140,988	139,661	412,170	407,261
Nuclear operating costs	28,766	67,449	80,002	190,028
Other operating costs	76,196	64,370	219,857	192,128
Provision for depreciation and amortization	46,232	42,443	157,850	147,111
General taxes	37,348	37,689	110,646	114,741
Income taxes	51,883	38,719	81,057	47,827
Total operating expenses and taxes	402,424	395,867	1,119,165	1,129,213
OPERATING INCOME	102,424	100,243	253,094	198,801
OTHER INCOME	8,264	6,196	29,485	15,621
NET INTEREST CHARGES:				
Interest on long-term debt	24,061	38,130	92,967	118,069
Allowance for borrowed funds used during construction	(1,056)	(1,920)	(3,782)	(5,724)
Other interest expense	5,239	163	12,750	199
Subsidiaries preferred stock dividend requirements		2,250		9,450
Net interest charges	28,244	38,623	101,935	121,994
INCOME BEFORE CUMULATIVE EFFECT	82,444	67,816	180,644	92,428

OF ACCOUNTING CHANGE				
Cumulative effect of accounting change (net of income taxes of $30,168,000) (Note 2)				42,378
NET INCOME	82,444	67,816	180,644	134,806
PREFERRED STOCK DIVIDEND REQUIREMENTS	1,754	1,865	5,253	2,970
EARNINGS ON COMMON STOCK	$ 80,690	$ 65,951	$ 175,391	$ 131,836

STATEMENTS OF COMPREHENSIVE INCOME				
NET INCOME	$ 82,444	$ 67,816	$ 180,644	$ 134,806
OTHER COMPREHENSIVE INCOME (LOSS):				
Minimum liability for unfunded retirement benefits				24,171
Unrealized gain (loss) on available for sale securities	991	3,873	(1,332)	22,826
Other comprehensive income (loss)	991	3,873	(1,332)	46,997
Income tax related to other comprehensive income	(406)	(1,611)	546	(19,774)
Other comprehensive income (loss), net of tax	585	2,262	(786)	27,223
TOTAL COMPREHENSIVE INCOME	$ 83,029	$ 70,078	$ 179,858	$ 162,029

The preceding Notes to Consolidated Financial Statements as they relate to The Cleveland Electric Illuminating Company are an integral part of these statements.

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THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2004	December 31, 2003
	(In thousands)	
ASSETS		
UTILITY PLANT:		
In service	$4,383,939	$4,232,335
Less-Accumulated provision for depreciation	1,941,362	1,857,588
	2,442,577	2,374,747
Construction work in progress-		
Electric plant	100,729	159,897
Nuclear fuel	9,634	21,338
	110,363	181,235
	2,552,940	2,555,982
OTHER PROPERTY AND INVESTMENTS:		
Investment in lessor notes	596,649	605,915
Nuclear plant decommissioning trusts	345,303	313,621
Long-term notes receivable from associated companies	97,830	107,946
Other	17,066	23,636
	1,056,848	1,051,118
CURRENT ASSETS:		
Cash and cash equivalents	200	24,782
Receivables-		
Customers	13,196	10,313
Associated companies	13,076	40,541
Other (less accumulated provisions of $844,000 and $1,765,000, respectively, for uncollectible accounts)	103,340	185,179

Notes receivable from associated companies	634	482
Materials and supplies, at average cost	58,327	50,616
Prepayments and other	1,102	4,511
	189,875	316,424
DEFERRED CHARGES:		
Regulatory assets	982,626	1,056,050
Goodwill	1,693,629	1,693,629
Property taxes	77,122	77,122
Other	26,674	23,123
	2,780,051	2,849,924
	$6,579,714	$6,773,448

CAPITALIZATION AND LIABILITIES

CAPITALIZATION:		
Common stockholder s equity-		
Common stock, without par value, authorized 105,000,000 shares- 79,590,689 shares outstanding	$1,281,962	$1,281,962
Accumulated other comprehensive income	1,867	2,653
Retained earnings	524,607	494,212
Total common stockholder s equity	1,808,436	1,778,827
Preferred stock not subject to mandatory redemption	96,404	96,404
Long-term debt and other long-term obligations	1,975,324	1,884,643
	3,880,164	3,759,874
CURRENT LIABILITIES:		
Currently payable long-term debt	76,690	387,414
Accounts payable-		
Associated companies	245,672	245,815
Other	9,374	7,342
Notes payable to associated companies	331,140	188,156
Accrued taxes	150,027	202,522
Accrued interest	35,501	37,872
Lease market valuation liability	60,200	60,200
Other	36,292	76,722

	944,896	1,206,043
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	498,920	486,048
Accumulated deferred investment tax credits	62,202	65,996
Asset retirement obligation	267,693	254,834
Retirement benefits	84,284	105,101
Lease market valuation liability	683,300	728,400
Other	158,255	167,152
	1,754,654	1,807,531
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Note 3)		
	$6,579,714	$6,773,448

The preceding Notes to Consolidated Financial Statements as they relate to The Cleveland Electric Illuminating Company are an integral part of these balance sheets.

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THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2004	2003	2004	2003
	(In thousands)			
CASH FLOWS FROM OPERATING ACTIVITIES:				
Net income	$ 82,444	$ 67,816	$ 180,644	$ 134,806
Adjustments to reconcile net income to net cash from operating activities-				
Provision for depreciation and amortization	46,232	42,443	157,850	147,111
Nuclear fuel and capital lease amortization	7,804	4,178	20,420	12,217
Other amortization	(3,336)	(7,911)	(12,877)	(12,933)
Deferred operating lease costs, net	(14,324)	(36,167)	(56,182)	(77,992)
Deferred income taxes, net	14,320	14,847	15,186	48,784
Amortization of investment tax credits	(1,301)	(1,202)	(3,794)	(3,605)
Accrued retirement benefit obligations	2,854	26,453	10,900	10,566
Accrued compensation, net	1,303	257	3,232	(4,056)
Cumulative effect of accounting change (Note 2)				(72,546)
Pension trust contribution	(31,718)		(31,718)	
Receivables	(3,422)	234,672	106,421	86,460
Materials and supplies	(2,238)	(2,164)	(7,711)	8,647
Prepayments and other current assets	1,512	(479)	3,409	714
Accounts payable	60,237	(235,048)	1,889	(55,802)
Accrued taxes	(15,630)	46,327	(52,495)	33,765
Accrued interest	(3,218)	7,996	(2,371)	4,428
Other	(10,010)	(36,610)	(40,193)	(5,882)
Net cash provided from operating activities	131,509	125,408	292,610	254,682
CASH FLOWS FROM FINANCING ACTIVITIES:				
New Financing-				
Long-term debt	44,330		125,238	
Short-term borrowings, net	213,682		132,770	
Redemptions and Repayments-				
Preferred Stock	(1,000)	(1,000)	(1,000)	(1,093)

Long-term debt	(327,171)	(256)	(335,272)	(146,321)
Short-term borrowings, net		(123,711)		(73,490)
Dividend Payments-				
Common stock			(145,000)	
Preferred stock	(1,755)	(1,864)	(5,253)	(5,594)
Net cash used for financing activities	(71,914)	(126,831)	(228,517)	(226,498)
CASH FLOWS FROM INVESTING ACTIVITIES:				
Property additions	(32,238)	(29,620)	(70,967)	(91,643)
Loan repayments from (loans to) associated companies, net	(850)	(5,574)	9,964	(5,354)
Investments in lessor notes	(11,699)	30,891	9,266	49,962
Contributions to nuclear decommissioning trusts	(7,256)	(14,512)	(21,768)	(21,768)
Other	(7,552)	20,238	(15,170)	10,396
Net cash provided from (used for) investing activities	(59,595)	1,423	(88,675)	(58,407)
Net change in cash and cash equivalents			(24,582)	(30,223)
Cash and cash equivalents at beginning of period	200	159	24,782	30,382
Cash and cash equivalents at end of period	$ 200	$ 159	$ 200	$ 159

The preceding Notes to Consolidated Financial Statements as they relate to The Cleveland Electric Illuminating Company are an integral part of these statements.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and Board of
Directors of The Cleveland
Electric Illuminating Company:

We have reviewed the accompanying consolidated balance sheet of The Cleveland Illuminating Electric Company and its subsidiaries as of September 30, 2004, and the related consolidated statements of income, comprehensive income and cash flows for each of the three-month and nine-month periods ended September 30, 2004 and 2003. These interim financial statements are the responsibility of the Company s management.

We conducted our review in accordance with the standards of the Public Company Accounting Oversight Board (United States). A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the Public Company Accounting Oversight Board, the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our review, we are not aware of any material modifications that should be made to the accompanying consolidated interim financial statements for them to be in conformity with accounting principles generally accepted in the United States of America.

We previously audited in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet and the consolidated statement of capitalization as of December 31, 2003, and the related consolidated statements of income, common stockholder s equity, preferred stock, cash flows and taxes for the year then ended (not presented herein), and in our report (which contained references to the Company s change in its method of accounting for asset retirement obligations as of January 1, 2003 as discussed in Note 1(F) to those consolidated financial statements and the Company s change in its method of accounting for the consolidation of variable interest entities as of December 31, 2003 as discussed in Note 7 to those consolidated financial statements) dated February 25, 2004 we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying condensed consolidated balance sheet as of December 31, 2003, is fairly stated in all material respects in relation to the consolidated balance sheet from which it has been derived.

PricewaterhouseCoopers LLP
Cleveland, Ohio
November 2, 2004

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THE CLEVELAND ELECTRIC ILLUMINATING COMPANY

MANAGEMENT S DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS AND FINANCIAL CONDITION

CEI is a wholly owned, electric utility subsidiary of FirstEnergy. CEI conducts business in portions of Ohio, providing regulated electric distribution services. CEI also provides generation services to those customers electing to retain CEI as their power supplier. CEI provides power directly to alternative energy suppliers under CEI s transition plan. CEI has unbundled the price of electricity into its component elements including generation, transmission, distribution and transition charges. Power supply requirements of CEI are provided by FES an affiliated company.

Results of Operations

Earnings on common stock in the third quarter of 2004 increased to $81 million from $66 million in the third quarter of 2003. For the first nine months of 2004, earnings on common stock increased to $175 million from $132 million in the same period of 2003. Earnings on common stock in the first nine months of 2003 included an after-tax credit of $42 million from the cumulative effect of an accounting change due to the adoption of SFAS 143. Income before the cumulative effect was $92 million in the first nine months of 2003. Increased earnings in both 2004 periods resulted principally from higher operating revenues, lower nuclear operating costs and reduced interest charges partially offset by higher fuel and other operating costs compared to 2003. Revenues for both periods were higher due to significant increases in sales to FES. Lower nuclear operating costs in the third quarter and the first nine months of 2004, compared with the same periods of 2003, were due to reduced incremental maintenance costs associated with the Davis-Besse extended outage and the absence of nuclear refueling outages at Beaver Valley Unit 2 and the Perry Plant in 2003. Lower net interest charges in the third quarter and the first nine months of 2004, compared with the same periods of 2003, were primarily due to debt redemptions and refinancing activities.

Operating revenues increased by $9 million or 1.8% in the third quarter from the same period of 2003. Higher revenues resulted principally from a $39 million (49.5%) increase in wholesale sales (primarily to FES) due to increased nuclear generation available for sale which was partially offset by reduced generation sales revenue from franchise customers of $8 million. The reduction in retail generation revenues (residential $4 million and commercial $2 million) in the third quarter of 2004 reflected increases in electric generation services to residential and commercial customers provided by alternative suppliers as a percent of total sales deliveries in CEI s franchise area of 4.6 percentage points and 7.6 percentage points, respectively while the corresponding percentage for industrial customers decreased by 4.3 percentage points. Lower industrial sales unit prices offset the impact of an increase in kilowatt-hour sales to industrial customers. In the first nine months of 2004, operating revenues increased by $44 million (3.3%) primarily as a result of a $96 million increase in wholesale revenues (primarily to FES) due to increased available nuclear generation in the first nine months of 2004. The increase in wholesale revenues was partially offset by a 2.8% decrease in retail generation sales, which resulted in lower revenues of $19 million. Decreased retail generation revenues in the first nine months of 2004 reflected the same trend in shopping for generation providers (increases of 7.4 and 9.1 percentage points for residential and commercial customers, respectively, and a decrease of 3.7 percentage points for industrial customers). Residential and commercial revenues decreased due to lower kilowatt-hour sales and unit prices that were partially offset by an increase in revenue from higher industrial generation sales. The higher industrial revenues resulted from increased sales that were partially offset by lower unit prices.

Revenues from distribution throughput decreased by $22 million and $27 million in the third quarter and first nine months of 2004, respectively, as compared to the same periods of 2003, even though total distribution deliveries were nearly unchanged in the third quarter and increased 0.7% in the first nine months of 2004. Distribution deliveries to residential customers decreased 8.0% in the third quarter and 3.7% in the first nine months of 2004 resulting from cooler weather in the third quarter of 2004 as compared to the same quarter of 2003 which reduced air conditioning loads. An improving economy increased distribution deliveries to commercial and industrial customers in the third quarter and first nine months of 2004. Lower unit prices in all customer sectors for both periods offset the effect of higher distribution deliveries to commercial and industrial customers.

Under the Ohio transition plan, CEI provides incentives to customers to encourage switching to alternative energy providers $2 million of additional credits in the third quarter and $6 million of additional credits in the first nine months of 2004 compared with the corresponding periods of 2003. These revenue reductions are deferred for future recovery under the transition plan and do not materially affect current period earnings.

Changes in electric generation sales and distribution deliveries in the third quarter and first nine months of 2004 from the corresponding periods of 2003 are summarized in the following table:

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Changes in KWH Sales	Three Months	Nine Months
Increase (Decrease)		
Electric Generation:		
Retail	(1.1)%	(2.8)%
Wholesale	46.6%	39.7%
Total Electric Generation Sales	**23.2%**	**17.8%**
Distribution Deliveries:		
Residential	(8.0)%	(3.7)%
Commercial	3.3%	1.6%
Industrial	2.8%	2.9%
Total Distribution Deliveries	**(0.1)%**	**0.7%**

Operating Expenses and Taxes

Total operating expenses and taxes increased by $7 million in the third quarter of 2004 from the third quarter of 2003 and decreased by $10 million in the first nine months of 2004 from the first nine months of 2003. The following table presents changes from the prior year by expense category.

Operating Expenses and Taxes Changes	Three Months	Nine Months
	(In millions)	
Increase (Decrease)		
Fuel	$ 15	$ 27
Purchased power	1	5
Nuclear operating costs	(38)	189

283

183

Dividends payable

325

325

325

297

Debt due within one year	**1,263**	1,497	1,428	1,276
Total current liabilities	**5,411**	5,339	5,349	5,448
Long-term debt	**12,630**	12,480	12,280	11,809
Other long-term liabilities	**4,850**	4,603	4,819	4,932
Non-current liabilities of discontinued operations	**87**	-	-	-
Total liabilities	**22,978**	22,422		

	22,448
	22,189
Non-controlling interest	**2,892**
	2,905
	2,914
	2,908
SHAREHOLDERS' EQUITY	
Preferred shares	**1,670**
	1,670
	1,670
	1,670
Common shareholders' equity	
Common shares	**16,806**
	16,794
	16,790
	16,781
Contributed surplus	**1,076**

	1,071	1,065	1,061	
Deficit	**(4,871)**	(5,005)	(5,264)	(5,432)
Currency translation adjustment	**(71)**	(52)	(53)	(56)
Total common shareholders' equity	**12,940**	12,808	12,538	12,354
Total shareholders' equity	**14,610**	14,478	14,208	14,024
Total liabilities and shareholders' equity	**40,480**			

39,805
39,570
39,121

Number of common shares outstanding

927.3
926.7
926.4
925.9

Total Net Debt

13,418
13,597
13,182
12,705

Total Capitalization

30,920
30,980
30,304
29,637

Key ratios

Net debt : Total Capitalization	**43.4%**	43.9%	43.5%	42.9%
Net debt : Trailing 12 month EBITDA	**1.75**	1.76	1.72	1.68
EBITDA : Interest (trailing 12 month)	**7.76**	7.75	7.66	7.53

BCE Consolidated
Consolidated Cash Flow Data

($ millions, except where otherwise indicated)	**Q3 2005**	Q3 2004	$ change	**YTD September 2005**	YTD September 2004	$ change
Cash flows from operating activities						
Earnings from continuing operations	**459**	102	357	**1,532**	1,131	401
Adjustments to reconcile earnings from continuing operations to cash flows from operating activities:						
Amortization expense	**803**	769	34	**2,368**	2,305	63
Net benefit plans cost	**108**	61	47	**315**	189	126
Restructuring and other items	**31**	1,081	(1,050)	**32**	1,098	(1,066)
Net gains on investments	**-**	(325)	325	**(34)**	(331)	297
Future income taxes	**111**	(183)	294	**285**	(96)	381
Non-controlling interest	**57**	47	10	**193**	134	59
Contributions to employee pension plans	**(33)**	(32)	(1)	**(161)**	(88)	(73)
Other employee future benefit plan payments	**(24)**	(13)	(11)	**(69)**	(59)	(10)
Payments on restructuring and other items	**(24)**	(12)	(12)	**(153)**	(39)	(114)
Operating assets and liabilities	**198**	333	(135)	**(233)**	(32)	(201)
	1,686	1,828	(142)	**4,075**	4,212	(137)
Capital expenditures	**(968)**	(811)	(157)	**(2,619)**	(2,318)	(301)
Other investing activities	**-**	(2)	2	**(26)**	133	(159)
Cash dividends paid on preferred shares	**(21)**	(21)	-	**(64)**	(64)	-
Cash dividends paid by subsidiaries to non-controlling interest	**(47)**	(44)	(3)	**(157)**	(139)	(18)
Free Cash Flow from operations, before common dividends[2]	**650**	950	(300)	**1,209**	1,824	(615)
Cash dividends paid on common shares	**(306)**	(277)	(29)	**(889)**	(831)	(58)

Free Cash Flow from operations, after common dividends[2]	**344**	673	(329)	**320**	993	(673)
Business acquisitions	**(62)**	(646)	584	**(180)**	(952)	772
Business dispositions	**-**	4	(4)	**-**	20	(20)
Increase in investments	**(75)**	(12)	(63)	**(216)**	**(20)**	(196)
Decrease in investments	**-**	707	(707)	**7**	713	(706)
Free Cash Flow after investments and divestitures	**207**	726	(519)	**(69)**	754	(823)
Other financing activities						
Increase (decrease) in notes payable and bank advances	**(65)**	173	(238)	**121**	123	(2)
Issue of long-term debt	**200**	10	190	**1,191**	1,410	(219)
Repayment of long-term debt	**(211)**	(98)	(113)	**(1,042)**	(1,750)	708
Issue of common shares	**12**	8	4	**25**	16	9
Issue of equity securities by subsidiaries to non-controlling interest	**1**	-	1	**1**	7	(6)
Redemption of equity securities by subsidiaries from non-controlling interest	**(22)**	(4)	(18)	**(60)**	(58)	(2)
Other financing activities	**(27)**	**(18)**	(9)	**(82)**	(34)	(48)
	(112)	71	(183)	**154**	(286)	440
Cash used in continuing operations	**95**	797	(702)	**85**	468	(383)
Cash provided by (used in) discontinued operations	**-**	12	(12)	**10**	196	(186)
Net increase (decrease) in cash and cash equivalents	**95**	809	(714)	**95**	664	(569)
Cash and cash equivalents at beginning of period	**380**	577	(197)	**380**	722	(342)
Cash and cash equivalents at end of period	**475**	1,386	(911)	**475**	1,386	(911)

Other information

Capital expenditures as a percentage of revenues	**19.6%**	17.0%	(2.6) pts	**17.7%**	16.3%	(1.4) pts
Cash flow per share[5]	**$ 0.77**	$ 1.10	$ (0.33)	**$ 1.57**	$ 2.05	$ (0.48)
Annualized cash flow yield[6]	**8.8%**	15.1%	(6.3) pts	**5.5%**	9.9%	(4.4) pts
Common dividend payout	**69.4%**	337.8%	n.m.	**60.1%**	75.1%	(15.0) pts

BCE Consolidated

Consolidated Cash Flow Data Historical Trend

($ millions, except where otherwise indicated)	**YTD 2005**	**Q3 05**	Q2 05	Q1 05	Total 2004	Q4 04	Q3 04	Q2 04	Q1 04
Cash flows from operating activities									
Earnings from continuing operations	**1,532**	**459**	581	492	1,498	367	102	544	485
Adjustments to reconcile earnings from continuing operations to cash flows from operating activities:									
Amortization expense	**2,368**	**803**	792	773	3,108	803	769	769	767
Net benefit plans cost	**315**	**108**	104	103	256	67	61	65	63
Restructuring and other items	**32**	**31**	**5**	(4)	1,224	126	1,081	14	3
Net (gains) losses on investments	**(34)**	**-**	(32)	(2)	(319)	12	(325)	(1)	(5)
Future income taxes	**285**	**111**	65	109	(34)	62	(183)	33	54
Non-controlling interest	**193**	**57**	73	63	174	40	47	39	48
Contributions to employee pension plans	**(161)**	**(33)**	(34)	(94)	(112)	(24)	(32)	(27)	(29)
Other employee future benefit plan payments	**(69)**	**(24)**	(22)	(23)	(81)	(22)	(13)	(22)	(24)
Payments of restructuring and other items	**(153)**	**(27)**	(28)	(101)	(253)	(214)	(12)	(8)	(19)
Operating assets and liabilities	**(233)**	**198**	(54)	(377)	58	90	333	(282)	(83)
	4,075	**1,686**	1,450	939	5,519	1,307	1,828	1,124	1,260
Capital expenditures	**(2,619)**	**(968)**	(914)	(737)	(3,364)	(1,046)	(811)	(826)	(681)
Other investing activities	(26)	**-**	(11)	(15)	124	(9)	(2)	116	19
Cash dividends paid on preferred shares	**(64)**	**(21)**	(22)	(21)	(85)	(21)	(21)	(21)	(22)
Cash dividends paid by subsidiaries to non-controlling interest	**(157)**	**(47)**	(60)	(50)	(188)	(49)	(44)	(52)	(43)

Free Cash Flow from operations, before common dividends[2]	**1,209**	**650**	443	116	2,006	182	950	341	533
Cash dividends paid on common shares	**(889)**	**(306)**	(305)	(278)	(1,108)	(277)	(277)	(277)	(277)
Free Cash Flow from operations, after common dividends[2]	**320**	**344**	138	(162)	898	(95)	673	64	256
Business acquisitions	**(180)**	**(62)**	(35)	(83)	(1,299)	(347)	(646)	(247)	(59)
Business dispositions	**-**	**-**	-	-	20	-	4	-	16
Increase in investments	(216)	(75)	(13)	(128)	(58)	(38)	(12)	(8)	
Decrease in investments	**7**	**-**	5	2	713	-	707	-	6
Free Cash Flow after investments and divestitures	(69)	**207**	95	(371)	274	(480)	726	(191)	219
Other financing activities									
Increase (decrease) in notes payable and bank advances	**121**	(65)	341	(155)	130	7	173	(69)	19
Issue of long-term debt	**1,191**	**200**	206	785	1,521	111	10	74	1,326
Repayment of long-term debt	**(1,042)**	**(211)**	(747)	(84)	(2,391)	(641)	(98)	(718)	(934)
Issue of common shares	**25**	**12**	4	9	32	16	8	4	4
Issue of equity securities and convertible debentures by subsidiaries to non-controlling interest	**1**	**1**	-	-	8	1	-	-	7
Redemption of equity securities by subsidiaries from non-controlling interest	**(60)**	**(22)**	(21)	(17)	(58)	-	(4)	(12)	(42)
Other financing activities	**(82)**	**(27)**	(25)	(30)	(51)	(17)	(18)	32	(48)
	154	(112)	(242)	508	(809)	(523)	71	(689)	332
Cash provided by (used in) continuing operations	**85**	**95**	(147)	137	(535)	(1,003)	797	(880)	551
Cash provided by (used in) discontinued operations	**10**	**-**	1	9	193	(3)	12	(54)	238
Net increase (decrease) in cash and cash equivalents	**95**	**95**	(146)	146	(342)	(1,006)	809	(934)	789
Cash and cash equivalents at beginning of period	**380**	**380**	526	380	722	1,386	577	1,511	722
Cash and cash equivalents at end of period	**475**	**475**	380	526	380	380	1,386	577	1,511

Consists of:

Cash and cash equivalents of continuing operations	**475**	**475**	380	526	380	380	1,386	577	1,135
Cash and cash equivalents of discontinued operations	**-**	**-**	-	**-**	**-**	**-**	**-**	**-**	376
Total	**475**	**475**	380	526	380	380	1,386	577	1,511

Other information

Capital expenditures as a percentage of revenues	**17.7%**	**19.6%**	18.4%	15.2%	17.5%	21.0%	17.0%	17.3%	14.7%
Cash flow per share[5]	**$ 1.57**	**$ 0.77**	$ 0.58	$ 0.22	$ 2.33	$ 0.28	$ 1.10	$ 0.32	$ 0.63
Annualized cash flow yield[6]	**5.5%**	**8.8%**	6.6%	1.7%	7.5%	2.7%	15.1%	5.5%	8.4%
Common dividend payout	**60.1%**	**69.4%**	54.2%	58.6%	72.8%	66.4%	337.8%	50.0%	58.9%

Proportionate Net Debt, Preferreds and EBITDA

BCE Corporate and Bell Canada Net debt and preferreds

At September 30, 2005

($ millions, except where otherwise indicated)	**Bell Canada (excl. Aliant)**	**Aliant**	**Bell Canada Statutory**	**Inter-company eliminations**	**Total Bell Canada**	**BCE Inc. Corporate**
Cash and cash equivalents	73	(371)	**(298)**		**(299)**	**(3)**
Long-term debt	9,277	894	**10,171**	(350)	**9,821**	**2,000**
Debt due within one year	1,207	158	**1,365**	(297)	**1,068**	**-**
Long-term note receivable from BCH	(498)	-	**(498)**	498	**-**	**-**
PPA fair value increment [7]					**103**	**-**
Net debt	10,058	681	**10,739**	(149)	**10,693**	**1,997**
Preferred shares - Bell Canada [8]	1,100		**1,100**		**1,100**	**-**
Preferred shares - Aliant [8]		172	**172**		**172**	**-**

Perpetual Preferred shares - BCE	-	-	**-**		**-**	**1,670**
Nortel common shares at market	-	-	**-**		**-**	**(56)**
Net debt and preferreds	11,158	853	**12,011**	(149)	**11,965**	**3,611**

Proportionate net debt and preferreds, Trailing EBITDA

For the quarter ended September 30, 2005			**TOTAL EBITDA**					**PROPORTIONATE EBITDA**				
($ millions, except where otherwise indicated)	**% owned by BCE**	**Propor-tionate net debt and preferreds**	**Q3 05**	**Q2 05**	**Q1 05**	**Q4 04**	**Trailing**	**Q3 05**	**Q2 05**	**Q1 05**	**Q4 04**	**Trailing**
Bell Canada (excluding Aliant)	100%	**11,112** A	1,578	1,618	1,605	1,469	6,270	1,578	1,618	1,605	1,469	6,270
Aliant	53.2%	**454**	226	221	210	210	867	120	117	112	112	461
Total Bell Canada Consolidated		**11,566**	1,804	1,839	1,815	1,679	7,137	1,698	1,735	1,717	1,581	6,731
Other BCE												
Bell Globemedia	68.5%	**254**	46	114	83	124	367	23	68	49	73	213
Telesat	100%	**315**	70	71	63	60	264	70	71	63	60	264
CGI	29.8%	**16** B	44	37	37	40	158	44	37	37	40	158
Corporate and other	100%	**3,611**	(36)	(39)	(37)	(47)	(159)	(36)	(39)	(37)	(47)	(159)
Total Other BCE		**4,196**	124	183	146	177	630	101	137	112	126	476
Inter-segment eliminations			(29)	(21)	(23)	(25)	(98)	(29)	(21)	(23)	(25)	(98)
Total		**15,762**	**1,899**	**2,001**	**1,938**	**1,831**	**7,669**	**1,770**	**1,851**	**1,806**	**1,682**	**7,109**

A Bell Canada (excl. Aliant) net debt and preferred of $11,158 million less $149 million of inter-company eliminations plus $103 million upon consolidation (PPA fair value increment).

B CGI is proportionately consolidated.

Bell Canada Consolidated (1)
Operational Data

($ millions, except where otherwise indicated)	**Q3 2005**	Q3 2004	$ change	% change	**YTD September 2005**	YTD September 2004	$ change	% change
Revenues								
Local and access	**1,367**	1,395	(28)	(2.0 %)	**4,103**	4,175	(72)	(1.7 %)
Long distance	**510**	589	(79)	(13.4 %)	**1,566**	1,767	(201)	(11.4 %)
Wireless	**801**	727	74	10.2 %	**2,285**	2,076	209	10.1 %
Data	**1,001**	915	86	9.4 %	**2,918**	2,677	241	9.0 %
Video	**251**	213	38	17.8 %	**708**	631	77	12.2 %
Terminal sales and other	**396**	367	29	7.9 %	**1,213**	1,158	55	4.7 %
Total operating revenues	**4,326**	4,206	120	2.9 %	**12,793**	12,484	309	2.5 %
Operating expenses	**(2,522)**	(2,350)	(172)	(7.3 %)	**(7,335)**	(7,052)	(283)	(4.0 %)
EBITDA	**1,804**	1,856	(52)	(2.8 %)	**5,458**	5,432	26	0.5 %
EBITDA margin (%)	***41.7 %***	*44.1 %*		*(2.4) pts*	***42.7 %***	*43.5 %*		*(0.8) pts*
Amortization expense	**(756)**	(734)	(22)	(3.0 %)	**(2,234)**	(2,199)	(35)	(1.6 %)
Net benefit plans cost	**(110)**	(55)	(55)	(100.0 %)	**(323)**	(173)	(150)	(86.7 %)
Restructuring and other items	**(30)**	**(1,080)**	1,050	97.2. %	**(30)**	**(1,096)**	1,066	97.3 %
Operating income	**908**	(13)	921	n.m.	**2,871**	1,964	907	46.2 %
Other income	**15**	114	(99)	(86.8 %)	**39**	163	(124)	(76.1 %)
Interest expense	**(207)**	(215)	8	3.7 %	**(619)**	(651)	32	4.9 %
Pre-tax earnings	**716**	(114)	830	n.m.	**2,291**	1,476	815	55.2 %
Income taxes	(198)	75	(273)	n.m.	**(605)**	(366)	(239)	(65.3 %)
Non-controlling interest	(16)	2	(18)	n.m.	(49)	1	(50)	n.m.
Net Earnings	**502**	(37)	539	n.m.	**1,637**	1,111	526	47.3 %
Dividends on preferred shares	(14)	(16)	2	12.5 %	(41)	(49)	8	16.3 %
Net earnings applicable to common shares	**488**	(53)	541	n.m.	**1,596**	1,062	534	50.3 %

Other information

Cash flow information

Free Cash Flow (FCF)								
Cash from operating activities	**1,551**	1,756	(205)	(11.7 %)	3,878	4,040	(162)	(4.0 %)
Capital expenditures	**(873)**	(736)	(137)	(18.6 %)	**(2,386**)	(2,041)	(345)	(16.9 %)
Dividends and distributions	**(468)**	(445)	(23)	(5.2 %)	**(1,343**)	(1,385)	42	3.0 %
Other investing items	**4**	1	3	n.m.	**4**	(7)	**11**	n.m.
Total	**214**	576	(362)	(62.8 %)	153	607	(454)	(74.8 %)
Capital expenditures as a percentage of revenues (%)	**20.2 %**	17.5 %		(2.7) pts	**18.7 %**	16.3 %		(2.4) pts

Balance Sheet Information	**Sept. 30 2005**	Dec. 31 2004
Net Debt		
Long-term debt	**10,171**	9,166
Debt due within one year	**1,365**	1,352
Less: Cash and cash equivalents	**(298)**	(32)
Total Net Debt	**11,238**	10,486
Non-controlling interest	**1,125**	1,229
Total shareholders' equity	**10,067**	9,670
Total Capitalization	**22,430**	21,385
Net Debt: Total Capitalization	**50.1 %**	49.0 %
Net Debt: Trailing 12 month EBITDA	**1.57**	1.47
EBITDA : Interest (trailing 12 month)	**8.59**	8.24

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Bell Canada Consolidated (1)
Operational Data - Historical Trend

($ millions, except where otherwise indicated)	**YTD 2005**	**Q3 05**	**Q2 05**	Q1 05	Total 2004	Q4 04	Q3 04	Q2 04	Q1 04
Revenues									
Local and access	**4,103**	**1,367**	1,368	1,368	5,572	1,397	1,395	1,401	1,379
Long distance	**1,566**	**510**	518	538	2,327	560	589	572	606
Wireless	**2,285**	**801**	771	713	2,818	742	727	698	651
Data	**2,918**	**1,001**	966	951	3,640	963	915	870	892
Video	**708**	**251**	236	221	850	219	213	211	207
Terminal sales and other	**1,213**	**396**	399	418	1,580	422	367	420	371
Total operating revenues	**12,793**	**4,326**	**4,**258	4,209	16,787	4,303	4,206	4,172	4,106
Operating expenses	**(7,335)**	**(2,522)**	**(**2,419)	(2,394)	(9,676)	(2,624)	(2,350)	(2,351)	(2,351)
EBITDA	**5,458**	**1,804**	1,839	1,815	7,111	1,679	1,856	1,821	1,755
EBITDA margin (%)	***42.7 %***	***41.7 %***	*43.2 %*	*43.1 %*	*42.4 %*	*39.0 %*	*44.1 %*	*43.6 %*	*42.7 %*
Amortization expense	**(2,234)**	**(756)**	(746)	(732)	(2,962)	(763)	(734)	(733)	(732)
Net benefit plans cost	**(323)**	**(110)**	(107)	(106)	(235)	(62)	(55)	(58)	(60)
Restructuring and other items	**(30)**	**(30)**	(5)	5	(1,219)	(123)	(1,080)	**(13**)	(3)
Operating income (loss)	**2,871**	**908**	981	982	2,695	731	**(13**)	1,017	960
Other income	**39**	**15**	13	11	183	20	114	19	30
Interest expense	**(619)**	**(207)**	(206)	(206)	(863)	(212)	(215)	(216)	(220)
Pre-tax earnings (loss)	**2,291**	**716**	788	787	2,015	539	**(114**)	820	770
Income taxes	**(605**)	**(198**)	(178)	(229)	(506)	(140)	75	(245)	(196)
Non-controlling interest	**(49)**	**(16**)	**(17**)	(16)	9	8	2	9	(10)
Net earnings (loss) before extraordinary gain	**1,637**	**502**	593	542	1,518	407	**(37**)	584	564
Extraordinary gain	**-**	**-**	**-**	-	69	69	-	-	-
Net earnings	**1,637**	**502**	593	542	1,587	476	**(37**)	584	564
Dividends on preferred shares	**(41)**	**(14)**	(13)	(14)	(60)	(11)	(16)	(17)	(16)
Net earnings applicable to common shares	**1,596**	**488**	580	528	1,527	465	**(53**)	567	548

Other information

Cash flow information

Free Cash Flow (FCF)									
Cash from operating activities	**3,878**	**1,551**	1,467	860	5,333	1,293	1,756	1,089	1,195
Capital expenditures	**(2,386)**	**(873)**	(847)	(666)	(3,026)	(985)	(736)	(715)	(590)
Dividends and distributions	**(1,343)**	**(468)**	(453)	(422)	(1,736)	(351)	(445)	(437)	(503)
Other investing items	**4**	**4**	4	(4)	**(15**)	**(8**)	1	(1)	(7)
Total	**153**	**214**	171	**(232**)	556	**(51**)	576	(64)	95
Capital expenditures as a percentage of revenues (%)	**18.7 %**	**20.2 %**	19.9 %	15.8 %	18.0 %	22.9 %	17.5 %	17.1 %	14.4 %

Balance Sheet Information	**Sept. 30 2005**	June 30 2005	March 31 2005	Dec. 31 2004
Net Debt				
Long-term debt	**10,171**	10,023	9,657	9,166
Debt due within one year	**1,365**	1,500	1,634	1,352
Less: Cash and cash equivalents	**(298)**	(169)	(308)	(32)
Total Net Debt	**11,238**	11,354	10,983	10,486
Non-controlling interest	**1,125**	1,162	1,202	1,229
Total shareholders' equity	**10,067**	9,957	9,796	9,670
Total Capitalization	**22,430**	22,473	21,981	21,385
Net Debt: Total Capitalization	**50.1 %**	50.5 %	50.0 %	49.0 %
Net Debt : Trailing 12 month EBITDA	**1.57**	1.58	1.53	1.47
EBITDA : Interest (trailing 12 month)	**8.59**	8.57	8.45	8.24

Bell Canada Consolidated [(1)]
Statistical Data

	Q3 2005	Q3 2004	% change	**YTD September 2005**	YTD September 2004	% change
Wireline						
Local						
Network access services (k)						
Residential	8,133	8,427	(3.5 %)	**8,133**	8,427	(3.5 %)
Business	4,507	4,535	(0.6 %)	**4,507**	4,535	(0.6 %)
Total	12,640	12,962	(2.5 %)	**12,640**	12,962	(2.5 %)
SmartTouch feature revenues ($M)	**221**	234	(5.6 %)	**673**	706	(4.7 %)
Long Distance (LD)						
Conversation minutes (M)	**4,484**	4,435	1.1 %	**13,739**	13,511	1.7 %
Average revenue per minute ($)	**0.105**	0.120	(12.5 %)	**0.104**	0.119	(12.6 %)
Data						
Equivalent access lines (9) (k) - Ontario and Quebec						
Digital equivalent access lines (k)	4,847	4,197	15.5 %	**4,847**	4,197	15.5 %
Internet subscribers (10) (k)						
High Speed Internet net activations (k)	**106**	84	26.2 %	**326**	259	25.9 %
High Speed Internet subscribers (k)	2,134	1,717	24.3 %	**2,134**	1,717	24.3 %
Dial-up Internet subscribers (k)	621	775	(19.9 %)	**621**	775	(19.9 %)
	2,755	2,492	10.6 %	**2,755**	2,492	10.6 %
Wireless						
Cellular & PCS Net activations (k)						
Pre-paid	**73**	14	n.m	**144**	54	n.m.
Post-paid	**50**	95	(47.4 %)	**162**	242	(33.1 %)
	123	109	12.8 %	**306**	296	3.4 %
Cellular & PCS subscribers (k)						
Pre-paid	1,345	1,113	20.8 %	**1,345**	1,113	20.8 %
Post-paid	3,886	3,595	8.1 %	**3,886**	3,595	8.1 %
	5,231	4,708	11.1 %	**5,231**	4,708	11.1 %
Average revenue per unit (ARPU) ($/month)	**51**	50	2.0 %	**49**	49	0.0 %
Pre-paid	**14**	12	16.7 %	**13**	12	8.3 %
Post-paid	**63**	63	0.0 %	**60**	61	(1.6 %)

Churn (%) (average per month)	**1.5 %**	1.2 %	(0.3) pts	**1.6 %**	1.3 %	(0.3) pts
Pre-paid	**1.6 %**	1.9 %	0.3 pts	**1.8 %**	1.9 %	0.1 pts
Post-paid	**1.5 %**	1.0 %	(0.5) pts	**1.5 %**	1.1 %	(0.4) pts
Usage per subscriber (min/month)	**265**	258	2.7 %	**253**	246	2.8 %
Cost of acquisition (COA) (11) ($/sub)	**432**	381	(13.4 %)	**405**	415	2.4 %
Wireless EBITDA ($ millions)	**363**	334	8.7 %	**996**	913	9.1 %
Wireless EBITDA margin (12)	**44.0 %**	45.4 %	(1.4) pts	**42.7 %**	43.3 %	(0.6) pts
Wireless capital expenditures ($ millions)	**103**	95	(8.4 %)	**285**	237	(20.3 %)
Wireless capital expenditures as a percentage of revenue	12.9%	13.1%	0.2 pts	12.5 %	11.4 %	(1.1) pts
Paging subscribers (k)	364	449	(18.9 %)	**364**	449	(18.9 %)
Paging average revenue per unit ($/month)	**10**	10	0.0 %	**12**	10	20.0 %

Video (DTH and VDSL)

Total subscribers (k)	1,677	1,460	14.9 %	**1,677**	1,460	14.9 %
Net subscriber activations (k)	**82**	33	n.m.	**174**	73	n.m.
ARPU ($/month)	**51**	48	6.3 %	**49**	48	2.1 %
COA ($/sub)	**360**	548	34.3 %	**388**	586	33.8 %
Video EBITDA ($ millions)	**12**	(16)	n.m.	**22**	(15)	n.m.
Churn (%) (average per month)	**1.0 %**	1.1 %	0.1 pts	**0.9 %**	1.0 %	0.1 pts

Bell Canada Consolidated (1)
Statistical Data Historical Trend

	YTD 2005	**Q3 05**	Q2 05	Q1 05	Total 2004	Q4 04	Q3 04	Q2 04	Q1 04
Wireline									
Local									
Network access services (k)									
Residential		**8,133**	8,189	8,332		8,392	8,427	8,390	8,476
Business		**4,507**	4,511	4,513		4,513	4,535	4,548	4,541
Total		**12,640**	12,700	12,845		12,905	12,962	12,938	13,017

SmartTouch feature revenues ($M)	**673**	**221**	225	227	939	233	234	235	237
Long Distance (LD)									
Conversation minutes (M)	**13,739**	**4,484**	4,667	4,588	18,070	4,559	4,435	4,498	4,578
Average revenue per minute ($)	**0.104**	**0.105**	0.101	0.107	0.117	0.109	0.120	0.118	0.120
Data									
Equivalent access lines [9] (k) - Ontario and Quebec									
Digital equivalent access lines (k)		**4,847**	4,634	4,469		4,335	4,197	4,083	3,983
Internet subscribers [10] (k)									
High Speed Internet net activations (k)	**326**	**106**	92	128	350	91	84	65	110
High Speed Internet subscribers (k)		**2,134**	2,028	1,936		1,808	1,717	1,633	1,568
Dial-up Internet subscribers (k)		**621**	666	696		743	775	807	836
		2,755	2,694	2,632		2,551	2,492	2,440	2,404
Wireless									
Cellular & PCS net activations (k)									
Pre-paid	**144**	**73**	29	42	142	88	14	17	23
Post-paid	**162**	**50**	117	(5)	371	129	95	78	69
	306	**123**	146	37	513	217	109	95	92
Cellular & PCS subscribers (k)									
Pre-paid		**1,345**	1,272	1,243		1,201	1,113	1,099	1,082
Post-paid		**3,886**	3,836	3,719		3,724	3,595	3,500	3,422
		5,231	5,108	4,962		4,925	4,708	4,599	4,504
Average revenue per unit (ARPU) ($/month)	**49**	**51**	50	46	49	50	50	50	47
Pre-paid	**13**	**14**	16	11	12	13	12	11	11
Post-paid	**60**	**63**	61	57	61	61	63	62	59
Churn (%) (average per month)	**1.6 %**	**1.5 %**	1.6 %	1.6 %	1.3 %	1.4 %	1.2 %	1.3 %	1.3 %
Pre-paid	**1.8 %**	**1.6 %**	2.1 %	1.8 %	1.9 %	1.9 %	1.9 %	1.9 %	1.7 %
Post-paid	**1.5 %**	**1.5 %**	1.4 %	1.6 %	1.1 %	1.2 %	1.0 %	1.1 %	1.1 %
Usage per subscriber (min/month)	**253**	**265**	**262**	232	248	252	258	257	224

Cost of acquisition (COA) [11] ($/sub)	**405**	**432**	401	373	411	402	381	413	455
Wireless EBITDA ($ millions)	**996**	**363**	333	300	1,187	274	334	317	262
Wireless EBITDA margin [12]	**42.7 %**	**44.0 %**	42.4 %	41.4 %	41.5 %	36.2 %	45.4 %	44.9 %	39.6 %
Wireless capital expenditures ($ millions)	**285**	**103**	118	64	362	125	95	77	65
Wireless capital expenditures as a percentage of revenue	**12.5 %**	**12.9 %**	15.3 %	9.0 %	12.8 %	16.8 %	13.1 %	11.0 %	10.0 %
Paging subscribers (k)		**364**	385	404		427	449	469	493
Paging average revenue per unit ($/month)	**12**	**10**	10	15	10	9	10	10	10
Video (DTH and VDSL)									
Total subscribers (k)		**1,677**	1,595	1,532		1,503	1,460	1,427	1,403
Net subscriber activations (k)	**174**	**82**	63	29	116	43	33	24	16
ARPU ($/month)	**49**	**51**	50	48	49	49	48	49	48
COA ($/sub)	**388**	**360**	462	473	571	537	548	570	661
Video EBITDA ($ millions)	**22**	**12**	**6**	4	(19)	(4)	(16)		1
Churn (%) (average per month)	**0.9 %**	**1.0 %**	0.9 %	0.8 %	1.0 %	0.8 %	1.1 %	1.0 %	0.9 %

Accompanying Notes

(1) We have reclassified some of the figures for the comparative period to make them consistent with the current period's presentation.

(2) **Non-GAAP Financial Measures**

EBITDA

The term, EBITDA (earnings before interest, taxes, depreciation and amortization), does not have any standardized meaning prescribed by Canadian generally accepted accounting principles (GAAP). It is therefore unlikely to be comparable to similar measures presented by other companies. EBITDA is presented on a consistent basis from period to period.

We define EBITDA as operating revenues less operating expenses, which means it represents operating income before amortization expense, net benefit plans cost, and restructuring and other items.

We use EBITDA, among other measures, to assess the operating performance of our ongoing businesses without the effects of amortization expense, net benefit plans cost, and restructuring and other items. We exclude amortization expense and net benefit plans cost because they largely depend on the accounting methods and assumptions a company uses, as well as non-operating factors, such as the historical cost of capital assets and the fund performance of a company s pension plans. We exclude restructuring and other items because they are transitional in nature.

EBITDA allows us to compare our operating performance on a consistent basis. We believe that certain investors and analysts use EBITDA to measure a company s ability to service debt and to meet other payment obligations, or as a common valuation measurement in the telecommunications industry.

EBITDA should not be confused with net cash flows from operating activities. The most comparable Canadian GAAP financial measure is operating income.

EPS before net gains (losses) on investments and restructuring and other items
The term, EPS (earnings per share) before net gains (losses) on investments and restructuring and other items, does not have any standardized meaning prescribed by GAAP. It is therefore unlikely to be comparable to similar measures presented by other companies.

We use EPS before net gains (losses) on investments and restructuring and other items, among other measures, to assess the operating performance of our ongoing businesses without the effects of after-tax restructuring and other items and net gains on investments. We exclude these items because they affect the comparability of our financial results and could potentially distort the analysis of trends in business performance. The exclusion of these items does not imply they are necessarily non-recurring.

The most comparable Canadian GAAP financial measure is EPS.

FREE CASH FLOW
The term, free cash flow, does not have any standardized meaning prescribed by Canadian GAAP. It is therefore unlikely to be comparable to similar measures presented by other companies. Free cash flow is presented on a consistent basis from period to period.

We define free cash flow as cash from operating activities after capital expenditures, total dividends and other investing activities.

We consider free cash flow to be an important indicator of the financial strength and performance of our business because it shows how much cash is available to repay debt and to reinvest in our company. We believe that certain investors and analysts use free cash flow when valuing a business and its underlying assets.

The most comparable Canadian GAAP financial measure is cash from operating activities.

Accompanying Notes (continued)

(3) EBITDA margin is calculated as follows:

<u>EBITDA</u>

Operating revenues

(4) Effective Q2 2005 the total Wireless capital expenditures are segregated between the Consumer and Business segments. Prior quarters have been restated accordingly.

(5) Cash flow per share is calculated as follows:

Cash flow from operations less capital expenditures

Average number of common shares outstanding during the period

(6) Annualized cash flow yield is calculated as follows:

Free cash flow from operations before common dividends

Number of common shares outstanding at end of period multiplied by share price at end of period

Note: to annualize, multiply the most recent quarter's resultant by 4.

(7) Reflects an increase in the total Bell Canada debt as a result of the completion of the purchase price allocation (PPA) relating to the repurchase of SBC s 20% interest in Bell Canada, which resulted in an increase in long-term debt of $165 million. This increase in long-term debt will be applied against interest expense ($4 million in Q3 2005) over the remaining terms of the related long-term debt.

(8) At the BCE Consolidated level, Third Party Preferred Shares reflected in the financial statements of subsidiaries are included in non-controlling interest on the balance sheet.

(9) Digital equivalent access lines are derived by converting low capacity data lines (DS-3 and lower) to the equivalent number of voice grade access lines. Broadband equivalent access lines are derived by converting high capacity data lines (higher than DS-3) to the equivalent number of voice grade access lines.

Conversion factors	
DS-0	1
Basic ISDN	2
Primary ISDN	23
DS-1, DEA	24
DS-3	672
OC-3	2,016
OC-12	8,064
OC-48	32,256
OC-192	129,024
10 Base T	155
100 Base T	1,554
Gigabit E	15,554

(10) High Speed Internet subscribers include Consumer, Business and Wholesale. Dial-up Internet subscribers include Consumer and Business.

(11) Includes allocation of selling costs from Bell Canada and excludes costs of migrating from analog to digital. Cost of Acquisition (COA) per subscriber is reflected on a consolidated basis.

(12) Wireless EBITDA margins are calculated based on total Wireless operating revenues (i.e. external revenues as shown on pages 10 and 11 plus inter-company revenues).

Appendix A Reconciliation of Canadian Generally Accepted Accounting Principles (GAAP) to United States GAAP

We have prepared the interim consolidated financial statements according to Canadian GAAP. The tables below are a reconciliation of significant differences relating to the statement of operations and total shareholders equity reported according to Canadian GAAP and United States GAAP.

RECONCILATION OF NET EARNINGS

For the period ended September 30	**Three months**		**Nine months**	
($ million, except share amounts) (unaudited)	**2005**	2004	**2005**	2004
Canadian GAAP - Earnings from continuing operations	**459**	102	**1,532**	1,131
Adjustments				
Deferred costs (a)	-	5	**3**	11
Employee future benefits (b)	**(12)**	(20)	**(36)**	(61)
United States GAAP - Earnings from continuing operations	**447**	87	**1,499**	1,081
Discontinued operations - United States GAAP (h)	**-**	(2)	**(1)**	86
United States GAAP - Net earnings	**447**	85	**1,498**	1,167
Dividends on preferred shares (i)	**(22)**	(24)	**(64)**	(70)
United States GAAP - Net earnings applicable to common shares	**425**	61	**1,434**	1,097
Other comprehensive earnings items				
Change in currency translation adjustment	**(19)**	(14)	**(15)**	1
Change in unrealized gain (loss) on investments (g)	**5**	(224)	**86**	(11)
Comprehensive earnings	**411**	(177)	**1,505**	1,087

Net earnings per common share - basic				
Continuing operations	**0.46**	0.07	**1.55**	1.09
Discontinued operations	**-**	(0.01)	-	0.10
Net earnings	**0.46**	0.06	**1.55**	1.19
Net earnings per common share - diluted				
Continuing operations	**0.46**	0.07	**1.55**	1.09
Discontinued operations	-	-	**-**	0.09
Net earnings	**0.46**	0.07	**1.55**	1.18
Dividends per common share	**0.33**	0.30	**0.99**	0.90
Average number of common shares outstanding (millions)	**927.0**	924.6	**926.6**	924.4

Appendix A Reconciliation of Canadian Generally Accepted Accounting Principles (GAAP) to United States GAAP

STATEMENTS OF ACCUMULATED OTHER COMPREHENSIVE LOSS

($ millions) (unaudited)	**September 30 2005**	December 31 2004
Currency translation adjustment	**(71)**	(56)
Unrealized gain (loss) on investments (g)	**90**	4
Additional minimum liability for pensions (b)	**(193)**	(193)
Accumulated Other Comprehensive loss	**(174)**	(245)

RECONCILIATION OF TOTAL SHAREHOLDERS EQUITY

($ millions) (unaudited)	**September 30 2005**	December 31 2004
Canadian GAAP	**14,610**	14,024

Adjustments		
Deferred costs (a)	**(61)**	(67)
Employee future benefits (b)	**(617)**	(543)
Gain on disposal of investments and on reduction		
of ownership in subsidiary companies (c)	**163**	163
Other	**97**	114
Tax effect of the above adjustments (e)	**114**	81
Non-controlling interest effect of the above adjustments (f)	**103**	95
Unrealized gain (loss) on investments (g)	**90**	4
United States GAAP	**14,499**	13,871

DESCRIPTION OF UNITED STATES GAAP ADJUSTMENTS

(a) Deferred costs

Under Canadian GAAP, certain expenses can be deferred and amortized if they meet certain criteria. Under United States GAAP, these costs are expensed as incurred.

(b) Employee future benefits

The accounting for future benefits for employees under Canadian GAAP and United States GAAP is essentially the same, except for the recognition of certain unrealized gains and losses.

Canadian GAAP requires companies to recognize a pension valuation allowance for any excess of the accrued benefit asset over the expected future benefit. Changes in the pension valuation allowance are recognized in the consolidated statement of operations. United States GAAP does not specifically address pension valuation allowances. United States regulators have interpreted this to be a difference between Canadian and United States GAAP.

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Appendix A Reconciliation of Canadian Generally Accepted Accounting Principles (GAAP) to United States GAAP

(c) Gains or losses on investments

Under Canadian GAAP and United States GAAP, gains or losses on investments are calculated in a similar manner. Differences in Canadian GAAP and United States GAAP, however, may cause the underlying carrying value of the investment to be different. This will cause the resulting gain or loss to be different.

(d) Equity income

Under Canadian GAAP, we account for our joint venture investments, which are mainly comprised of CGI Group Inc., using the proportionate consolidation method. Under United States GAAP, we account for our joint venture investments using the equity method. There is no impact on net earnings.

Our proportionate share of our joint ventures operating results was as follows:

For the period ended September 30 ($ millions) (unaudited)	Three months 2005	Three months 2004	Nine months 2005	Nine months 2004
Operating revenues				
External	**230**	227	**702**	615
Inter-segment	**44**	47	**123**	121
Total revenues	**274**	274	**825**	736
Operating expenses	**(236)**	(236)	**(724)**	(630)
Amortization expense	**(17)**	(14)	**(48)**	(36)
Total operating expenses	**(253)**	(250)	**(772)**	(666)
Operating income	**21**	24	**53**	70
Other income	**-**	1	**5**	3
Interest expense	**(2)**	(1)	**(6)**	(3)
Pre-tax earnings from continuing operations	**19**	24	**52**	70
Income taxes	**(7)**	(9)	**(20)**	(26)
Earnings from continuing operations	**12**	15	**32**	44
Discontinued operations	**-**	-	**(1)**	3
Net earnings	**12**	15	**31**	47

(e) Income taxes

The income tax adjustment represents the impact the United States GAAP adjustments that we describe above have on income taxes. The accounting for income taxes under Canadian GAAP and United States GAAP is essentially the same, except that:

income tax rates of enacted or substantively enacted tax law are used to calculate future income tax assets and liabilities under Canadian GAAP

only enacted income tax rates are used under United States GAAP.

(f) Non-controlling interest

The non-controlling interest adjustment represents the impact the United States GAAP adjustments that we describe above have on non-controlling interest.

(g) Change in unrealized gain (loss) on investments

Our portfolio investments are recorded at cost under Canadian GAAP. They would be classified as available-forsale under United States GAAP and would be carried at fair value, with any unrealized gains or losses included in other comprehensive loss, net of tax.

(h) Discontinued operations

Differences between Canadian GAAP and United States GAAP will cause the historical carrying values of the net assets of discontinued operations to be different.

Appendix A Reconciliation of Canadian Generally Accepted Accounting Principles (GAAP) to United States GAAP

(i) Accounting for stock-based compensation

In December 2002, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 148, *Accounting for Stock-Based Compensation Transition and Disclosure*. It applies to fiscal years ending after December 15, 2002. It amends the transitional provisions of SFAS No. 123 for companies that choose to recognize stock-based compensation under the fair value-based method of SFAS No. 123, instead of choosing to continue following the intrinsic value method of Accounting Principles Board Opinion (APB) No. 25.

We adopted the fair value-based method of accounting on a prospective basis, effective January 1, 2002.

Under SFAS No. 123, however, we are required to make pro forma disclosures of net earnings, and basic and diluted earnings per share, assuming that the fair value-based method of accounting had been applied from the date that SFAS No. 123 was adopted. The table below shows the stock-based compensation expense and pro forma net earnings using the Black-Scholes pricing model.

	Three months		Nine months	
For the period ended September 30 (unaudited)	**2005**	2004	**2005**	2004
Net earnings, as reported	**447**	85	**1,498**	1,167
Compensation cost included in net earnings	**18**	16	**37**	40
Total compensation cost	**(18)**	(18)	**(38)**	(47)
Pro forma net earnings	**447**	83	**1,497**	1,160
Pro forma net earnings per common share - basic	**0.46**	0.07	**1.55**	1.18
Pro forma net earnings per common share - diluted	**0.46**	0.07	**1.55**	1.18

(j) Accounting for derivative instruments and hedging activities (SFAS No. 133)

On January 1, 2001, we adopted SFAS No. 133, *Accounting for Derivatives Instruments and Hedging Activities*, as amended by SFAS No. 138. Under this standard, all derivatives must be recorded on the balance sheet at fair value under United States GAAP. In addition, certain economic hedging strategies, such as using dividend rate swaps to hedge preferred share dividends and hedging SCPs, no longer qualify for hedge accounting under United States GAAP.

The change in the fair value of derivative contracts that no longer qualify for hedge accounting under United States GAAP is reported in net earnings.

We elected to settle the dividend rate swaps used to hedge $510 million of BCE Inc. Series AA preferred shares and $510 million of BCE Inc. Series AC preferred shares in the third quarter of 2003. These dividend rate swaps in effect converted the fixed-rate dividends on these preferred shares to floating-rate dividends. They were to mature in 2007. As a result of the early settlement, we received total proceeds of $83 million in cash. After the settlement, all of our derivative contracts qualify for hedge accounting. Under Canadian GAAP, the proceeds are being deferred and amortized against the dividends on these preferred shares over the remaining original terms of the swaps. Under United States GAAP, these dividend rate swaps did not qualify for hedge accounting and were recorded on the balance sheet at fair value. As a result, the amortization of the deferred gain under Canadian GAAP is reversed for purposes of United States GAAP.

Certification of Interim Filings during Transition Period

I, Michael J. Sabia, President and Chief Executive Officer of BCE Inc., certify that:

1. I have reviewed the interim filings (as this term is defined in Multilateral Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings) of BCE Inc. (the issuer) for the interim period ending September 30, 2005;

2. Based on my knowledge, the interim filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the interim filings; and

3. Based on my knowledge, the interim financial statements together with the other financial information included in the interim filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the interim filings.

Dated: November 2, 2005

By: *(signed) Michael J. Sabia*

Michael J. Sabia
President and Chief Executive Officer
BCE Inc.

Certification of Interim Filings
during Transition Period

I, Siim A. Vanaselja, Chief Financial Officer of BCE Inc., certify that:

1. I have reviewed the interim filings (as this term is defined in Multilateral Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings) of BCE Inc. (the issuer) for the interim period ending September 30, 2005;

2. Based on my knowledge, the interim filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the interim filings; and

3. Based on my knowledge, the interim financial statements together with the other financial information included in the interim filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the interim filings.

Dated: November 2, 2005

By: *(signed) Siim A. Vanaselja*

Siim A. Vanaselja
Chief Financial Officer
BCE Inc.

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

BCE Inc.

(signed) Siim A. Vanaselja

Siim A. Vanaselja
Chief Financial Officer

Date: November 2, 2005