

METROPOLITAN EDISON COMPANY
2006 ANNUAL REPORT TO STOCKHOLDERS

Metropolitan Edison Company is a wholly owned electric utility subsidiary of FirstEnergy Corp. It engages in the transmission, distribution and sale of electric energy in 3,300 square miles of eastern and south central Pennsylvania. It also engages in the sale, purchase and interchange of electric energy with other electric companies. The area it serves has a population of approximately 1.2 million.

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GLOSSARY OF TERMS

The following abbreviations and acronyms are used in this report to identify Metropolitan Edison Company and its affiliates:

ATSI	American Transmission Systems, Inc., owns and operates transmission facilities
CEI	The Cleveland Electric Illuminating Company, an affiliated Ohio electric utility
Companies	OE, CEI, TE, Penn, JCP&L, Met-Ed and Penelec
FES	FirstEnergy Solutions Corp., provides energy-related products and services
FESC	FirstEnergy Service Company, provides legal, financial, and other corporate support services
FirstEnergy	FirstEnergy Corp., a public utility holding company
GPU	GPU, Inc., former parent of JCP&L, Met-Ed and Penelec, which merged with FirstEnergy on November 7, 2001
JCP&L	Jersey Central Power & Light Company, an affiliated New Jersey electric utility
Met-Ed	Metropolitan Edison Company
NGC	FirstEnergy Nuclear Generation Corp., owns nuclear generating facilities
OE	Ohio Edison Company, an affiliated Ohio electric utility
Penelec	Pennsylvania Electric Company, an affiliated Pennsylvania electric utility
Penn	Pennsylvania Power Company, an affiliated Pennsylvania electric utility
TE	The Toledo Edison Company, an affiliated Ohio electric utility

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

ALJ	Administrative Law Judge
AOCL	Accumulated Other Comprehensive Loss
ARO	Asset Retirement Obligation
CBP	Competitive Bid Process
CTC	Competitive Transition Charge
ECAR	East Central Area Reliability Coordination Agreement
EPACT	Energy Policy Act of 2005
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN	FASB Interpretation
FIN 46R	FIN 46 (revised December 2003), "Consolidation of Variable Interest Entities"
FIN 47	FIN 47, "Accounting for Conditional Asset Retirement Obligations – an interpretation of FASB Statement No. 143"
FIN 48	FIN 48, "Accounting for Uncertainty in Income Taxes-an interpretation of FASB Statement No. 109"
Fitch	Fitch Ratings, Ltd.
FMB	First Mortgage Bonds
FSP	FASB Staff Position
FSP SFAS 115-1 and SFAS 124-1	FASB Staff Position No. 115-1 and SFAS 124-1, "The Meaning of Other-Than-Temporary Impairment and its Application to Certain Investments"
FSP FIN 46(R)-6	FASB Staff Position No. FIN 46(R)-6, "Determining the Variability to Be Considered in Applying FASB interpretation No. 46(R)"
GAAP	Accounting Principles Generally Accepted in the United States
KWH	Kilowatt-hours
MISO	Midwest Independent Transmission System Operator, Inc.
Moody's	Moody's Investors Service
NERC	North American Electric Reliability Corporation
NOPR	Notice of Proposed Rulemaking
NUG	Non-Utility Generation
OCI	Other Comprehensive Income
OPEB	Other Post-Employment Benefits
PJM	PJM Interconnection LLC
PLR	Provider of Last Resort
PPUC	Pennsylvania Public Utility Commission
PRP	Potentially Responsible Party
PUCO	Public Utilities Commission of Ohio
RFP	Request For Proposal
RTOR	Regional Through and Out Rates
S&P	Standard & Poor's Ratings Service
SEC	United States Securities and Exchange Commission
SFAC	Statement of Financial Accounting Concepts
SFAC 7	SFAC No. 7, "Using Cash Flow Information and Present Value in Accounting Measurements"

GLOSSARY OF TERMS, Cont'd.

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 101	SFAS No. 101, "Accounting for Discontinuation of Application of SFAS 71"
SFAS 106	SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions"
SFAS 107	SFAS No. 107, "Disclosures about Fair Value of Financial Instruments"
SFAS 115	SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities"
SFAS 133	SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities"
SFAS 142	SFAS No. 142, "Goodwill and Other Intangible Assets"
SFAS 143	SFAS No. 143, "Accounting for Asset Retirement Obligations"
SFAS 144	SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets"
SFAS 157	SFAS No. 157, "Fair Value Measurements"
SFAS 158	SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans-an amendment of FASB Statements No. 87, 88, 106, and 132(R)"
SFAS 159	SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities – Including an amendment of FASB Statement No. 115"
TMI-1	Three Mile Island Unit 1
TMI-2	Three Mile Island Unit 2
VIE	Variable Interest Entity

Report of Independent Registered Public Accounting Firm

To the Stockholder and Board of
Directors of Metropolitan Edison Company:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, capitalization, common stockholder's equity, preferred stock and cash flows present fairly, in all material respects, the financial position of Metropolitan Edison Company and its subsidiaries at December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

Our audit was conducted for the purpose of forming an opinion on the basic financial statements taken as a whole. The Supplemental Consolidated Statements of Taxes is presented for purposes of additional analysis and is not a required part of the basic financial statements. Such information has been subjected to the auditing procedures applied in the audit of the basic financial statements and, in our opinion, is fairly stated in all material respects in relation to the basic financial statements taken as a whole.

As discussed in Note 3 to the consolidated financial statements, the Company changed the manner in which it accounts for defined benefit pension and other postretirement benefit plans as of December 31, 2006. As discussed in Note 2(G) and Note 9 to the consolidated financial statements, the Company changed its method of accounting for conditional asset retirement obligations as of December 31, 2005.

PricewaterhouseCoopers LLP
Cleveland, Ohio
February 27, 2007

The following selected financial data should be read in conjunction with, and is qualified in its entirety by reference to, the sections entitled "Management's Discussion and Analysis of Results of Operations and Financial Condition" and with our consolidated financial statements and the "Notes to Consolidated Financial Statements." Our Consolidated Statements of Income are not necessarily indicative of future conditions or results of operations.

METROPOLITAN EDISON COMPANY

SELECTED FINANCIAL DATA

<u>For the Years Ended December 31,</u>	<u>2006</u>	<u>2005</u>	<u>2004</u>	<u>2003</u>	<u>2002</u>
	<i>(Dollars in thousands)</i>				
GENERAL FINANCIAL INFORMATION:					
Operating Revenues	<u>\$ 1,243,058</u>	<u>\$ 1,176,418</u>	<u>\$ 1,070,847</u>	<u>\$ 969,788</u>	<u>\$ 986,608</u>
Operating Income (Loss)	<u>\$ (158,945)</u>	<u>\$ 75,422</u>	<u>\$ 108,165</u>	<u>\$ 83,938</u>	<u>\$ 91,271</u>
Income (Loss) Before Cumulative Effect of a Change in Accounting Principles	<u>\$ (240,195)</u>	<u>\$ 45,919</u>	<u>\$ 66,955</u>	<u>\$ 60,953</u>	<u>\$ 63,224</u>
Net Income (Loss)	<u>\$ (240,195)</u>	<u>\$ 45,609</u>	<u>\$ 66,955</u>	<u>\$ 61,170</u>	<u>\$ 63,224</u>
Total Assets	<u>\$ 2,614,279</u>	<u>\$ 2,917,687</u>	<u>\$ 3,243,546</u>	<u>\$ 3,472,709</u>	<u>\$ 3,564,716</u>
CAPITALIZATION AS OF DECEMBER 31:					
Common Stockholder's Equity	\$ 1,014,939	\$ 1,316,099	\$ 1,285,419	\$ 1,292,667	\$ 1,315,586
Company-Obligated Mandatorily Preferred Securities		-	-	-	92,409
Long-Term Debt and Other Long-Term Obligations	542,009	591,888	701,736	636,301	538,790
Total Capitalization	<u>\$ 1,556,948</u>	<u>\$ 1,907,987</u>	<u>\$ 1,987,155</u>	<u>\$ 1,928,968</u>	<u>\$ 1,946,785</u>
CAPITALIZATION RATIOS:					
Common Stockholder's Equity	65.2 %	69.0 %	64.7 %	67.0 %	67.6 %
Company-Obligated Mandatorily Preferred Securities	-	-	-	-	4.7
Long-Term Debt and Other Long-Term Obligations	34.8	31.0	35.3	33.0	27.7
Total Capitalization	<u>100.0 %</u>	<u>100.0 %</u>	<u>100.0 %</u>	<u>100.0 %</u>	<u>100.0 %</u>
DISTRIBUTION KWH DELIVERIES (Millions):					
Residential	5,287	5,399	5,071	4,900	4,738
Commercial	4,509	4,491	4,251	4,034	3,991
Industrial	4,008	4,083	4,042	4,047	3,972
Other	35	36	33	36	35
Total	<u>13,839</u>	<u>14,009</u>	<u>13,397</u>	<u>13,017</u>	<u>12,736</u>
CUSTOMERS SERVED:					
Residential	477,690	471,333	464,287	455,073	448,334
Commercial	61,381	60,413	59,495	58,825	58,010
Industrial	1,827	1,859	1,868	1,906	1,936
Other	782	721	730	732	728
Total	<u>541,680</u>	<u>534,326</u>	<u>526,380</u>	<u>516,536</u>	<u>509,008</u>
NUMBER OF EMPLOYEES:					
	701	678	651	659	*

* Met-Ed's employees were employed by GPU Service Company in 2002.

METROPOLITAN EDISON COMPANY

Management's Discussion and Analysis of Results of Operations and Financial Condition

Forward-Looking Statements: *This discussion 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 materially due 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, the continued ability to collect transition and other charges or to recover increased transmission costs, maintenance costs being higher than anticipated, legislative and regulatory changes (including revised environmental requirements), and the legal and regulatory changes resulting from the implementation of the Energy Policy Act of 2005 (including, but not limited to, the repeal of the Public Utility Holding Company Act of 1935), the uncertainty of the timing and amounts of the capital expenditures, adverse regulatory or legal decisions and outcomes (including, but not limited to, the revocation of necessary licenses or operating permits, fines or other enforcement actions and remedies) of governmental investigations and oversight, including by the Securities and Exchange Commission, the Nuclear Regulatory Commission and the Pennsylvania Public Utility Commission, including the transition rate plan filings for Met-Ed and Penelec, the continuing availability and operation of generating units, the inability to accomplish or realize anticipated benefits from strategic goals (including employee workforce initiatives), the anticipated benefits from voluntary pension plan contributions, the ability to improve electric commodity margins and to experience growth in the distribution business, the ability to access the public securities and other capital markets and the cost of such capital, the outcome, cost and other effects of present and potential legal and administrative proceedings and claims related to the August 14, 2003 regional power outage, the risks and other factors discussed from time to time in our Securities and Exchange Commission filings, and other similar factors. Also, a credit rating should not be viewed as a recommendation to buy, sell or hold securities and may be revised or withdrawn by a rating agency at any time. We expressly disclaim any current intention to update any forward-looking statements contained herein as a result of new information, future events, or otherwise.*

Reclassifications

As discussed in Note 1 to the consolidated financial statements, certain prior year amounts have been reclassified to conform to the current year presentation. These reclassifications did not change previously reported earnings for 2005 and 2004. All reclassifications have been evaluated and determined to be properly reflected as reclassifications in the respective period as presented in the Consolidated Balance Sheets and Statements of Cash Flows.

Results of Operations

In 2006, we recognized a net loss of \$240 million compared to net income of \$46 million in 2005, primarily due to a \$355 million non-cash goodwill impairment charge in the fourth quarter of 2006 (see Note 2(E)). Excluding the impairment charge, earnings increased \$69 million primarily due to increased revenues and the deferral of new regulatory assets, partially offset by increased purchased power costs and general taxes.

Net income decreased to \$46 million in 2005 compared to \$67 million in 2004, primarily due to higher purchased power costs, general taxes and other operating costs, partially offset by higher operating revenues and other income.

Revenues

Revenues increased by \$66 million, or 5.7%, in 2006 compared with 2005 primarily due to higher retail generation electric revenues of \$50 million as a result of higher composite prices in all customer classes. Higher KWH sales to industrial and commercial customers were offset by lower KWH sales to residential customers. Industrial KWH sales increased primarily due to the return of customers from alternate suppliers. Sales by alternative suppliers as a percent of total industrial sales in our franchise area decreased by 10.4 percentage points in 2006 compared with 2005. KWH sales to residential customers decreased primarily due to significantly milder weather in 2006 as compared with 2005. Revenues from distribution throughput decreased by \$2 million in 2006 primarily due to lower KWH deliveries, offset by higher composite unit prices. KWH deliveries decreased as a result of the milder weather in 2006 – cooling degree days decreased by 18.2% and heating degree days decreased by 15.8% as compared to 2005. Transmission revenues increased primarily due to higher transmission prices and additional PJM auction revenue rights in 2006, which also resulted in higher transmission expenses as discussed below. Other revenues also increased due to a \$2 million increase in the payment received in 2006 under a contract provision associated with the prior sale of TMI Unit 1, compared with 2005. Under the contract, additional payments are received if energy prices rise above specified levels. The payment is credited to our customers, resulting in no earnings impact.

Revenues increased by \$106 million, or 9.9%, in 2005 primarily as a result of higher sales levels compared with 2004. Retail generation revenues increased by \$47 million due to an 8.8% increase in KWH sales. Generation sales increased in all customer sectors in 2005, reflecting the unusually warmer summer temperatures and reduced customer shopping in 2005. Industrial customer shopping decreased by 11.1 percentage points in 2005 from 2004. Revenues from distribution throughput increased by \$25 million primarily due to a 4.6% increase in KWH deliveries which reflected the effect of the warmer summer temperatures and slightly higher composite unit prices. The higher KWH deliveries also contributed to increased transmission revenues of \$30 million. In 2005, other operating revenues included a \$4 million payment received under a contract provision associated with the prior sale of TMI Unit 1 as discussed above.

Changes in electric generation sales and distribution deliveries in 2006 and 2005 are summarized in the following table:

Changes in KWH Sales	2006	2005
<i>Increase (Decrease)</i>		
Retail Electric Generation:		
Residential	(1.9)%	6.5 %
Commercial	1.2 %	6.5 %
Industrial	9.5 %	15.5 %
Total Electric Generation Sales	2.2 %	8.8 %
Distribution Deliveries:		
Residential	(2.1)%	6.5 %
Commercial	0.4 %	5.6 %
Industrial	(1.8)%	1.0 %
Total Distribution Deliveries	(1.2)%	4.6 %

Expenses

Total expenses increased by \$301 million in 2006 and by \$138 million in 2005. The following table presents changes from the prior year expense category:

Expenses - Changes	2006	2005
<i>Increase (Decrease)</i>		
		<i>(In millions)</i>
Purchased power costs	\$ 14	\$ 66
Other operating costs	53	61
Provision for depreciation	(1)	1
Amortization of regulatory assets	4	6
Deferral of new regulatory assets	(127)	-
Goodwill impairment	355	-
General taxes	3	4
Net increase in expenses	\$ 301	\$ 138

Purchased power costs increased by \$14 million in 2006, compared with 2005, primarily due to increased KWH purchases to meet higher customer demand, higher composite unit prices, and a \$10 million charge related to incremental NUG costs deferred in 2005 under a revised accounting methodology, partially offset by increased NUG cost deferrals. Other operating costs increased primarily due to higher transmission expenses, reflecting the higher transmission prices as discussed above. The deferral of new regulatory assets reflects the May 4, 2006 PPUC approval of our request to defer certain 2006 transmission-related costs (see Regulatory Matters). The goodwill impairment is the result of an interim review of our goodwill following the January 11, 2007, PPUC order regarding our comprehensive rate filing, which allows for a rate increase that is substantially less than we requested (see Note 2(E)).

Purchased power costs increased by \$66 million in 2005, compared with 2004. The increase reflected a 7.3% increase in KWH purchases in order to meet higher retail generation sales requirements, partially offset by the effect of lower unit costs. NUG contract deferrals were also \$33 million lower than 2004. Other operating costs increased by \$61 million in 2005 primarily due to higher transmission expenses necessary to support the increased KWH sales as discussed above. General taxes increased by \$4 million primarily due to increased gross receipt taxes from the increased retail generation sales in 2005 as compared to 2004.

Other Income (Expense)

Other income decreased by \$5 million in 2006 as compared to 2005 primarily due to a \$2 million decrease in interest income earned on our regulatory assets, reflecting a lower regulatory asset base, and a \$3 million increase in interest expense primarily due to increased borrowings through our accounts receivable financing facility with Met-Ed Funding as discussed further below.

Other income increased by \$4 million in 2005 as compared to 2004 primarily due to a gain from the sale of the Easton Service Center property and a decrease in interest expense due to a reduction in long-term debt outstanding, partially offset by higher interest expenses resulting from increased intercompany loans through the money pool as discussed further below.

Cumulative Effect of a Change in Accounting Principle

Results in 2005 include an after-tax charge to net income of \$310,000 recorded upon the adoption of FIN 47 in December 2005. We identified applicable legal obligations as defined under the new standard at our substation control rooms, service center buildings, line shops and office buildings, identifying asbestos as the primary conditional ARO. As a result of adopting FIN 47, we recorded a conditional ARO liability of \$628,000 (including accumulated accretion for the period from the date the liability was incurred to the date of adoption), an asset retirement cost of \$148,000 (recorded as part of the carrying amount of the related long-lived asset) and accumulated depreciation of \$50,000.

Capital Resources and Liquidity

Our cash requirements in 2006 for operating expenses, construction expenditures and scheduled debt maturities were met with a combination of cash from operations and short-term credit arrangements. We plan to issue long-term debt during 2007 to fund maturing long-term debt obligations. During 2007 and thereafter, we expect to meet our contractual obligations with a combination of cash from operations, short-term credit arrangements, and funds from the capital markets.

Changes in Cash Position

As of December 31, 2006, we had cash and cash equivalents of \$130,000 compared with \$120,000 as of December 31, 2005. The major sources of changes in these balances are summarized below.

Cash Flows From Operating Activities

Cash flows provided from operating activities totaled \$222 million in 2006, \$125 million in 2005, and \$74 million in 2004. The sources of these changes are as follows:

Operating Cash Flows	2006	2005	2004
		<i>(In millions)</i>	
Net Income ⁽¹⁾	\$ (240)	\$ 46	\$ 67
Net non-cash charges ⁽¹⁾	347	79	50
Pension trust contributions ⁽²⁾	3	(25)	(23)
Working capital	112	25	(20)
Net cash provided from operating activities	\$ 222	\$ 125	\$ 74

⁽¹⁾ Includes goodwill impairment of \$355 million in 2006.

⁽²⁾ Pension trust contributions in 2005 and 2004 are net of \$11 million and \$16 million of income tax benefits, respectively. The \$3 million cash inflow in 2006 represents reduced income taxes paid in 2006 relating to a January 2007 pension contribution.

Net cash provided from operating activities increased \$97 million in 2006 compared to 2005 primarily due to a \$268 million increase in non-cash charges, an \$87 million increase in working capital, the absence of a \$25 million after-tax voluntary pension trust contribution in 2006, and a \$3 million tax benefit in 2006 relating to the January 2007 pension contribution, partially offset by a \$286 million decrease in net income. Changes in net income and non-cash charges are described under "Results of Operations." Working capital increased primarily due to a \$145 million change in accounts payable, partially offset by a \$41 million decrease in receivables, a \$12 million change in accrued taxes, and a \$2 million increase in cash collateral paid to suppliers.

Net cash provided from operating activities increased \$51 million in 2005 as compared to 2004 resulting from increases of \$45 million from working capital changes and \$29 million in non-cash charges described under "Results of Operations", partially offset by a \$2 million after-tax voluntary pension trust contribution increase and a \$21 million decrease in net income. The increase from working capital was principally due a \$144 million increase in cash provided from the settlement of receivables partially offset by an \$86 million cash reduction in payables.

Cash Flows From Financing Activities

Net cash used for financing activities was \$124 million in 2006 compared to \$32 million in 2005. This increase primarily reflects an \$87 million decrease in new financings and a \$34 million increase in long-term debt redemptions, partially offset by a \$29 million decrease in common stock dividend payments to FirstEnergy.

Net cash used for financing activities of \$32 million in 2005 compares to net cash provided from financing activities of \$11 million in 2004. The net change of \$43 million reflects an \$89 million decrease in long-term debt financing, offset by a \$45 million increase in short-term borrowings and a \$1 million decrease in common stock dividend payments to FirstEnergy.

The following table provides details regarding new issues and redemptions during each year:

Securities Issued or Redeemed	2006	2005	2004
		<i>(In millions)</i>	
New Issues:			
Pollution control notes	\$ -	\$ 29	\$ -
Unsecured notes	-	-	247
	\$ -	\$ 29	\$ 247
Redemptions:			
FMB	\$ 100	\$ 66	\$ 90
Subordinated debentures	-	-	100
Other	-	-	6
	\$ 100	\$ 66	\$ 196
Short-term Borrowings, net	\$ 1	\$ 60	\$ 15

We had approximately \$31 million of cash and temporary investments (which included short-term notes receivable from associated companies) and approximately \$142 million of short-term indebtedness as of December 31, 2006. We have authorization from the FERC to incur short-term debt of up to \$250 million and authorization from the PPUC to incur money pool borrowings of up to \$300 million. In addition, we have \$80 million of available accounts receivable financing facilities as of December 31, 2006 from Met-Ed Funding, our wholly owned subsidiary. As a separate legal entity with separate creditors, Met-Ed Funding would have to satisfy its obligations to creditors before any of its remaining assets could be made available to us. In June 2006, the facility was renewed until June 28, 2007. The annual facility fee is 0.125% on the entire finance limit. As of December 31, 2006, the facility was not drawn.

Under the terms of our senior note indenture, FMBs may not be issued so as long as senior notes are outstanding. As of December 31, 2006, we had the capability to issue \$653 million of additional senior notes based upon FMB collateral. We have no restrictions on the issuance of preferred stock.

On August 24, 2006, we, FirstEnergy, OE, Penn, CEI, TE, JCP&L, Penelec, FES, and ATSI, as Borrowers, entered into a new \$2.75 billion five-year revolving credit facility, which replaced FirstEnergy's prior \$2 billion credit facility. Subject to specified conditions, FirstEnergy may request an increase in the total commitments available under the new facility up to a maximum of \$3.25 billion. Commitments under the new facility are available until August 24, 2011, unless the lenders agree, at the request of the Borrowers, to two additional one-year extensions. Generally, borrowings under the facility must be repaid within 364 days. Available amounts for each Borrower are subject to a specified sublimit, as well as applicable regulatory and other limitations. Our borrowing limit under the facility is \$250 million.

Under the revolving credit facility, Borrowers may request the issuance of letters of credit expiring up to one year from the date of issuance. The stated amount of outstanding letters of credit will count against total commitments available under the facility and against the applicable borrower's borrowing sublimit. Total unused borrowing capability under existing credit facilities and accounts receivable financing facilities totaled \$330 million as of December 31, 2006.

The revolving credit facility contains financial covenants requiring each Borrower to maintain a consolidated debt to total capitalization ratio of no more than 65%. As of December 31, 2006, our debt to total capitalization ratios, as defined under the revolving credit facility, was 42%.

The revolving credit facility does not contain provisions that either restrict the ability to borrow or accelerate repayment of outstanding advances as a result of any change in credit ratings. Pricing is defined in "pricing grids", whereby the cost of funds borrowed under the facility is related to the credit ratings of the company borrowing the funds.

We have the ability to borrow from our regulated affiliates and FirstEnergy to meet our 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. Companies receiving a loan under the money pool agreements must repay the principal, 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 2006 was 5.22%.

Our access to capital markets and costs of financing are influenced by the ratings of our securities and that of FirstEnergy. The following table displays FirstEnergy's and ours securities ratings as of December 31, 2006. The ratings outlook from S&P on all securities is stable. The ratings outlook from Moody's on all securities is positive. The ratings outlook from Fitch on all securities is stable.

<u>Ratings of Securities</u>	<u>Securities</u>	<u>S&P</u>	<u>Moody's</u>	<u>Fitch</u>
FirstEnergy	Senior unsecured	BBB-	Baa3	BBB
Met-Ed	Senior unsecured	BBB	Baa2	BBB

Cash Flows From Investing Activities

Cash used for investing activities increased to \$98 million in 2006 from \$94 million in 2005, primarily due to an increase in loan repayments to associated companies.

Cash used for investing activities increased to \$94 million in 2005 from \$85 million in 2004, reflecting more property additions in 2005, partially offset by an increase in loan repayments from associated companies.

Our capital spending for the period 2007 through 2011 is expected to be about \$511 million for energy delivery related improvements, of which approximately \$83 million applies to 2007. The capital spending is primarily for property additions supporting the distribution of electricity.

Contractual Obligations

As of December 31, 2006, our estimated cash payments under existing contractual obligations that we consider firm obligations are as follows:

<u>Contractual Obligations</u>	<u>Total</u>	<u>2007</u>	<u>2008- 2009</u>	<u>2010- 2011</u>	<u>Thereafter</u>
			<i>(In millions)</i>		
Long-term debt ⁽¹⁾	\$ 592	\$ 50	\$ -	\$ 100	\$ 442
Short-term borrowings	142	142	-	-	-
Operating leases ⁽²⁾	65	4	8	7	46
Interest on long-term debt	188	27	52	45	64
Pension funding ⁽³⁾	11	11	-	-	-
Purchases ⁽⁴⁾	2,609	517	929	573	590
Total	\$ 3,607	\$ 751	\$ 989	\$ 725	\$ 1,142

⁽¹⁾ Amounts reflected do not include interest on long-term debt.

⁽²⁾ Operating lease payments are net of reimbursements from subleasees (see Note 5 – Leases).

⁽³⁾ We estimate that no further pension contributions will be required during the 2008-2011 period to maintain our defined benefit pension plan's funding at a minimum required level as determined by government regulations. We are unable to estimate projected contributions beyond 2011. See Note 3 to the consolidated financial statements.

⁽⁴⁾ Power purchases under contracts with fixed or minimum quantities and approximate timing.

Market Risk Information

We use various market risk sensitive instruments, including derivative contracts, primarily to manage the risk of price and interest rate fluctuations. Our Risk Policy Committee, comprised of members of senior management, provides general oversight to risk management activities.

Commodity Price Risk

We are exposed to market risk primarily due to fluctuations in electricity, energy transmission, natural gas, coal, and emission prices. To manage the volatility relating to these exposures, we use a variety of non-derivative and derivative instruments, including forward contracts, options, futures contracts, and swaps. The derivatives are used principally for hedging purposes. All derivatives that fall within the scope of SFAS 133 must be recorded at their fair value and marked to market. The majority of our derivative hedging contracts qualify for the normal purchase and normal sale exception under SFAS 133. On April 1, 2006, we elected to apply the normal purchase and normal sale exception to certain NUG power purchase agreements having an above-market fair value of \$1 million (included in "Other" in the table below). The change in the fair value of commodity derivative contracts related to energy production during 2006 is summarized in the following table:

Increase (Decrease) in the Fair Value of Derivative Contracts	Non-Hedge	Hedge	Total
	<i>(In millions)</i>		
Change in the fair value of commodity derivative contracts			
Outstanding net liability as of January 1, 2006	\$ 27	\$ -	\$ 27
New contract value when entered	-	-	-
Additions/Changes in value of existing contracts	4	-	4
Change in techniques/assumptions	-	-	-
Settled contracts	(9)	-	(9)
Other	1	-	1
Net Assets - Derivatives Contracts as of December 31, 2006⁽¹⁾	\$ 23	\$ -	\$ 23
Impact of Changes in Commodity Derivative Contracts⁽²⁾			
Income Statement Effects (Pre-Tax)	\$ (2)	\$ -	\$ (2)
Balance Sheet Effects:			
OCI (Pre-Tax)	\$ -	\$ -	\$ -
Regulatory Asset (net)	\$ 3	\$ -	\$ 3

⁽¹⁾ Includes \$23 million from an embedded option that is offset by a regulatory liability and does not affect earnings.

⁽²⁾ Represents the change in value of existing contracts, settled contracts and changes in techniques/assumptions.

Derivatives are included on the Consolidated Balance Sheet as of December 31, 2006 as follows:

	Non-Hedge	Hedge	Total
	<i>(In millions)</i>		
Non-Current-			
Other Deferred Charges	\$ 23	\$ -	\$ 23
Other noncurrent liabilities	-	-	-
Net assets	\$ 23	\$ -	\$ 23

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, we rely on model-based information. The model provides estimates of future regional prices for electricity and an estimate of related price volatility. We use 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 as of December 31, 2006 are summarized by year in the following table:

Source of Information - Fair Value by Contract Year	2007	2008	2009	2010	2011	Thereafter	Total
	<i>(In millions)</i>						
Other external sources ⁽¹⁾	\$ 5	\$ 5	\$ 5	\$ 4	\$ -	\$ -	\$ 19
Prices based on models	-	-	-	-	4	-	4
Total⁽²⁾	\$ 5	\$ 5	\$ 5	\$ 4	\$ 4	\$ -	\$ 23

⁽¹⁾ Broker quote sheets.

⁽²⁾ Includes \$23 million from an embedded option that is offset by a regulatory liability and does not affect earnings.

We perform sensitivity analyses to estimate our exposure to the market risk of our commodity positions. A hypothetical 10% adverse shift in quoted market prices in the near term on both our trading and non-trading derivative instruments would not have had a material effect on our consolidated financial position or cash flows as of December 31, 2006. We estimate that if energy commodity prices experienced an adverse 10% change, net income for the next twelve months would not change, as the prices for all commodity positions are already above the contract price caps.

Interest Rate Risk

We are subject to the inherent interest rate risks related to refinancing maturing debt by issuing new debt securities. Our exposure to fluctuations in market interest rates is reduced since a significant portion of our debt has fixed interest rates, as noted in the table below.

Comparison of Carrying Value to Fair Value

Year of Maturity	2007	2008	2009	2010	2011	There- after	Total	Fair Value
<i>(Dollars in millions)</i>								
<u>Assets</u>								
Investments Other Than Cash and Cash Equivalents- Fixed Income Average interest rate						\$ 105 4.9%	\$ 105 4.9%	\$ 106
<u>Liabilities</u>								
Long-term Debt:								
Fixed rate	\$ 50			\$ 100		\$ 414 4.9%	\$ 564 4.9%	\$ 543
Average interest rate	5.9%			4.5%				
Variable rate						\$ 28 3.8%	\$ 28 3.8%	\$ 29
Average interest rate								
Short-term Borrowings	\$ 142						\$ 142	\$ 142
Average interest rate	5.6%						5.6%	

Equity Price Risk

Included in nuclear decommissioning trusts are marketable equity securities carried at their current fair value of approximately \$164 million and \$142 million as of December 31, 2006 and 2005, respectively. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a \$16 million reduction in fair value as of December 31, 2006 (see Note 4 – Fair Value of Financial Instruments).

Regulatory Matters

All of our customers are able to select alternative energy suppliers. We continue to deliver power to homes and businesses through our existing distribution system, which remains regulated. The PPUC authorized our rate restructuring plan, establishing separate charges for transmission, distribution, generation and stranded cost recovery, which is recovered through a CTC. Customers electing to obtain power from an alternative supplier have their bills reduced based on the regulated generation component, and the customers receive a generation charge from the alternative supplier. We have a continuing responsibility referred to as our PLR obligation to provide power to those customers not choosing to receive power from an alternative energy supplier, subject to certain limits.

Regulatory assets are costs which have been authorized by the PPUC and the FERC for recovery from customers in the future periods or for which authorization is probable. Without the probability of such authorization, costs currently recorded as regulatory assets would have been charged to income as incurred. All regulatory assets are expected to be recovered under the provisions of our transition plan and rate restructuring plan. Our regulatory assets as of December 31, 2006 and December 31, 2005 were \$409 million and \$310 million, respectively.

A February 2002 Commonwealth Court of Pennsylvania decision affirmed the June 2001 PPUC decision regarding approval of the FirstEnergy/GPU merger, remanded the issues of quantification and allocation of merger savings to the PPUC and denied the Company's the rate relief initially approved in the PPUC decision. On May 4, 2006, the PPUC consolidated the merger savings proceeding with the April 10, 2006 comprehensive rate filing proceeding discussed below. On January 11, 2007, the PPUC entered an order in that rate filing proceeding and determined that no merger savings from prior years should be considered in determining customers' rates.

On January 12, 2005, the Company filed, before the PPUC, a request for deferral of transmission-related costs beginning January 1, 2005. The company sought to consolidate this proceeding (and modified its request to provide deferral of 2006 transmission-related costs only) with the comprehensive rate filing made on April 10, 2006, described below. On May 4, 2006, the PPUC approved the modified request.

We have been purchasing a portion of our PLR requirements from FES through a partial requirements wholesale power sales agreement and various amendments. Under these agreements, FES retained the supply obligation and the supply profit and loss risk for the portion of power supply requirements not self-supplied by us. The FES agreements have reduced our exposure to high wholesale power prices by providing power at a fixed price for our uncommitted PLR capacity and energy costs during the term of these agreements with FES.

On April 7, 2006, we entered into a Tolling Agreement with FES that arose from FES' notice to terminate the partial requirements agreement effective midnight December 31, 2006. On November 29, 2006, we agreed with FES to suspend the April 7 Tolling Agreement pending resolution of the PPUC's proceedings regarding our Transition Rate case filed April 10, 2006, described below. Separately, on September 26, 2006, we successfully conducted a competitive RFP for a portion of our PLR obligation for the period December 1, 2006 through December 31, 2008. FES was one of the successful bidders in that RFP process and on September 26, 2006 entered into a Supplier Master Agreement to supply a certain portion of our PLR requirements at market prices that substantially exceed the fixed price in the partial requirements agreements.

Based on the outcome of the Transition Rate filing, as described below, we agreed with FES to restate the partial requirements power sales agreement effective January 1, 2007. The restated agreement incorporates the same fixed price for residual capacity and energy supplied by FES as in the prior arrangements, and automatically extends for successive one year terms unless any party gives 60 days' notice prior to the end of the year. The restated agreement allows us to sell the output of NUG generation to the market and requires FES to provide energy at fixed prices to replace any NUG energy thus sold to the extent needed for us to satisfy our PLR obligations. We have also separately terminated the Tolling, Suspension and Supplier Master agreements in connection with the restatement of the partial requirements agreement. Accordingly, the energy that would have been supplied under the Master Supplier Agreement will now be provided under the restated partial requirements agreement.

If we were to replace the entire FES supply at current market power prices without corresponding regulatory authorization to increase our generation prices to customers, we would likely incur a significant increase in operating expenses and experience a material deterioration in credit quality metrics. Under such a scenario, our credit profile would no longer be expected to support an investment grade rating for our fixed income securities. Based on the PPUC's January 11, 2007 order described below, if FES ultimately determines to terminate, reduce, or significantly modify the agreement prior to the expiration of our generation rate caps in 2010, timely regulatory relief is not likely to be granted by the PPUC.

We made a comprehensive rate filing with the PPUC on April 10, 2006 to address a number of transmission, distribution and supply issues. If our preferred approach involving accounting deferrals was approved, the filing would have increased our annual revenues by \$216 million. That filing included, among other things, a request to charge customers for an increasing amount of market priced power procured through a CBP as the amount of supply provided under the then existing FES agreement is phased out in accordance with the April 7, 2006 Tolling Agreement described above. We also requested approval of the January 12, 2005 petition for the deferral of transmission-related costs discussed above, but only for those costs incurred during 2006. In this rate filing, we also requested recovery of annual transmission and related costs incurred on or after January 1, 2007, plus the amortized portion of 2006 costs over a ten-year period, along with applicable carrying charges, through an adjustable rider similar to that implemented in Ohio. Changes in the recovery of NUG expenses and the recovery of our non-NUG stranded costs were also included in the filing. Hearings were held in late August 2006 and briefing occurred in September and October. The ALJs issued their Recommended Decision on November 2, 2006.

The PPUC entered its Opinion and Order in the rate filing proceeding on January 11, 2007. The Order approved the recovery of transmission costs, including the 2006 deferral, and determined that no merger savings from prior years should be considered in determining customers' rates. The request for increases in generation supply rates was denied as were the requested changes in NUG expense recovery and our non-NUG stranded costs. The order decreased our distribution rates by \$80 million. These decreases were offset by the increases allowed for the recovery of transmission expenses and the 2006 transmission deferral. Our overall rates increased by 5.0% or \$59 million. We filed a Petition for Reconsideration on January 26, 2007 on the issues of consolidated tax savings and rate of return on equity. Other parties filed Petitions for Reconsideration on transmission congestion, transmission deferrals and rate design issues. The PPUC on February 8, 2007 entered an order granting Met-Ed's, Penelec's and the other parties' petitions for procedural purposes. Due to that ruling, the period for appeals to the Commonwealth Court is tolled until 30 days after the PPUC enters a subsequent order ruling on the substantive issues raised in the petitions.

As of December 31, 2006, our regulatory deferrals pursuant to the 1998 Restructuring Settlement (including the Phase 2 Proceedings) and the FirstEnergy/GPU Merger Settlement Stipulation were \$303 million. During the PPUC's annual audit of our NUG stranded cost balances in 2006, it noted a modification to our NUG purchased power stranded cost accounting methodology. On August 18, 2006, a PPUC Order was entered requiring us to reflect the deferred NUG cost balances as if the stranded cost accounting methodology modification had not been implemented. As a result of the PPUC's Order, we recognized a pre-tax charge of approximately \$10.3 million in the third quarter of 2006, representing incremental costs deferred under the revised methodology in 2005. We continue to believe that the stranded cost accounting methodology modification is appropriate and on August 24, 2006 we filed a petition with the PPUC pursuant to its Order for authorization to reflect the stranded cost accounting methodology modification effective January 1, 1999. Hearings on this petition are scheduled for late February 2007. It is not known when the PPUC may issue a final decision in this matter.

On February 16, 2007, the FERC issued a final rule that revises its decade-old open access transmission regulations and policies. The FERC explained that the final rule is intended to strengthen non-discriminatory access to the transmission grid, facilitate FERC enforcement, and provide for a more open and coordinated transmission planning process. The final rule will not be effective until 60 days after publication in the Federal Register. The final rule has not yet been fully evaluated to assess its impact on our operations.

On February 1, 2007 the Governor of Pennsylvania proposed an Energy Independence Strategy (EIS). The EIS includes four pieces of preliminary draft legislation that, according to the Governor, is designed to reduce energy costs, promote energy independence and stimulate the economy. Elements of the EIS include the installation of smart meters, funding for solar panels on residences and small businesses, conservation programs to meet demand growth, a requirement that electric distribution companies acquire power through a "Least Cost Portfolio", the utilization of micro-grids and a three year phase-in of rate increases. Since the EIS has only recently been proposed, the final form of any legislation is uncertain. Consequently, FirstEnergy is unable to predict what impact, if any, such legislation may have on its operations.

See Note 7 to the consolidated financial statements for further details and a complete discussion of regulatory matters in Pennsylvania including a more detailed discussion of reliability initiatives, including actions by the PPUC, that impact us.

Environmental Matters

We accrue environmental liabilities only when we can conclude that it is probable that we have an obligation for such costs and can reasonably determine the amount of such costs. Unasserted claims, are reflected in our determination of environmental liabilities and are accrued in the period that they become both probable and reasonably estimable.

We have been named as a PRP 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 unsubstantial and subject to dispute; however, federal law provides that PRPs for a particular site are held liable on a joint and several basis. Therefore, environmental liabilities that are considered probable have been recognized on the Consolidated Balance Sheet as of December 31, 2006, based on estimates of the total costs of cleanup, our proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. Total liabilities of approximately \$48,000 have been accrued through December 31, 2006.

See Note 11(B) to the consolidated financial statements for further details and a complete discussion of environmental matters.

Legal Matters

There are various lawsuits, claims (including claims for asbestos exposure) and proceedings related to our normal business operations pending against us. The other material items not otherwise discussed above are described in Note 11 to the consolidated financial statements.

Critical Accounting Policies

We prepare our 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 our assets are subject to their own specific risks and uncertainties and are regularly reviewed for impairment. Our more significant accounting policies are described below.

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, we evaluate our 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 were indicated, we recognize a loss – calculated as the difference between the implied fair value of our goodwill and the carrying value of the goodwill. Our annual review was completed in the third quarter of 2006, with no impairment of goodwill indicated. The forecasts used in our evaluation of goodwill reflect operations consistent with our general business assumptions. Unanticipated changes in those assumptions could have a significant effect on our future evaluations of goodwill. On January 11, 2007, the PPUC issued its order related to our comprehensive rate filing on April 10, 2006. The rate increase granted was substantially lower than the amounts we requested. Prior to issuing the order, the PPUC conducted an informal, nonbinding polling of Commissioners at its public meeting on December 21, 2006 that indicated the rate increase ultimately granted would be substantially below the amounts that we requested. As a result of the polling, we determined that an interim review of goodwill would be required. As a result, we recognized an impairment charge of \$355 million in the fourth quarter of 2006. In the year ended December 31, 2005, we adjusted goodwill to reverse pre-merger tax accruals due to the final resolution of tax contingencies related to the GPU acquisition. As of December 31, 2006, we had approximately \$496 million of goodwill.

Revenue Recognition

We 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 sales is recognized. The determination of unbilled sales requires management to make estimates regarding electricity available for retail load, transmission and distribution line losses, demand by customer class, weather-related impacts, prices in effect for each customer class and electricity provided by alternative suppliers.

Regulatory Accounting

We are subject to regulation that sets the prices (rates) we are permitted to charge our customers based on costs that the regulatory agencies determine we 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 ratemaking process results in the recording of regulatory assets based on anticipated future cash inflows. We regularly review 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.

Pension and Other Postretirement Benefits Accounting

Our reported costs of providing non-contributory qualified and non-qualified 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 we make to the plans, and earnings on plan assets. Such factors may be further affected by business combinations, which impact 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, 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.

As of December 31, 2006, we adopted SFAS 158 which requires a net liability or asset to be recognized for the overfunded or underfunded status of our defined benefit pension and other postretirement benefit plans on the balance sheet and recognize changes in funded status in the year in which the changes occur through other comprehensive income. We will continue to apply the provisions of SFAS 87 and SFAS 106 in measuring plan assets and benefit obligations as of the balance sheet date and in determining the amount of net periodic benefit cost. Our underfunded status at December 31, 2006 is \$637 million

In selecting an assumed discount rate, we consider 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. The assumed discount rate as of December 31, 2006 is 6.00% from 5.75% and 6.00% used as of December 31, 2005 and 2004, respectively.

Our assumed rate of return on pension plan assets considers historical market returns and economic forecasts for the types of investments held by our pension trusts. In 2006, 2005 and 2004, plan assets actually earned \$567 million or 12.5%, \$325 million or 8.2% and \$415 million or 11.1%, respectively. Our pension costs in 2006, 2005 and 2004 were computed using an assumed 9.0% rate of return on plan assets which generated \$396 million, \$345 million and \$286 million expected returns on plan assets, respectively. The 2006 expected return was based upon projections of future returns and our pension trust investment allocation of approximately 64% equities, 29% bonds, 5% real estate, 1% private equities and 1% cash. The gains or losses generated as a result of the difference between expected and actual returns on plan assets are deferred and amortized and will increase or decrease future net periodic pension expense, respectively.

Our pension and OPEB expense was \$94 million in 2006 and \$131 million in 2005. On January 2, 2007 FirstEnergy made a \$300 million voluntary contribution to our pension plan (our share was \$11 million). In addition during 2006, we amended our OPEB plan effective in 2008 to cap our monthly contribution for many of the retirees and their spouses receiving subsidized health care coverage. As a result of the \$300 million voluntary contribution and the amendment to the OPEB plan effective in 2008, we expect the pension and OPEB costs for 2007 to be a credit of \$94 million for FirstEnergy.

Health care cost trends have significantly increased and will affect future OPEB costs. The 2006 and 2005 composite health care trend rate assumptions are approximately 9-11%, gradually decreasing to 5% in later years. In determining our trend rate assumptions, we included the specific provisions of our 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. The effect on our portion of pension and OPEB costs from changes in key assumptions are as follows:

Increase in Costs from Adverse Changes in Key Assumptions

<u>Assumption</u>	<u>Adverse Change</u>	<u>Pension</u>	<u>OPEB</u>	<u>Total</u>
			<i>(In millions)</i>	
Discount rate	Decrease by 0.25 %	\$ 0.9	\$ 0.2	\$ 1.1
Long-term return on assets	Decrease by 0.25 %	\$ 1.1	\$ 0.2	\$ 1.3
Health care trend rate	Increase by 1 %	na	\$ 0.5	\$ 0.5

Long-Lived Assets

In accordance with SFAS 144, we periodically evaluate our 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, we recognize 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.

Asset Retirement Obligations

In accordance with SFAS 143 and FIN 47, we recognize an ARO for the future decommissioning of our nuclear power plants and future remediation of other environmental liabilities associated with all of our long-lived assets. The ARO liability represents an estimate of the fair value of our current obligation related to nuclear decommissioning and the retirement or remediation of environmental liabilities of other assets. A fair value measurement inherently involves uncertainty in the amount and timing of settlement of the liability. We used an expected cash flow approach to measure the fair value of the nuclear decommissioning and environmental remediation 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; settlement based on an extended license term and expected remediation dates.

New Accounting Standards and Interpretations Adopted

SFAS 159 – “The Fair Value Option for Financial Assets and Financial Liabilities – Including an amendment of FASB Statement No. 115”

In February 2007, FASB issued SFAS 159, which provides companies with an option to report selected financial assets and liabilities at fair value. The Standard requires companies to provide additional information that will help investors and other users of financial statements to more easily understand the effect of the company's choice to use fair value on its earnings. The Standard also requires companies to display the fair value of those assets and liabilities for which the company has chosen to use fair value on the face of the balance sheet. This guidance does not eliminate disclosure requirements included in other accounting standards, including requirements for disclosures about fair value measurements included in SFAS 157, *Fair Value Measurements*, and SFAS 107, *Disclosures about Fair Value of Financial Instruments*. We are currently evaluating the impact of this Statement on our financial statements.

SFAS 157 – “Fair Value Measurements”

In September 2006, the FASB issued SFAS 157 that establishes how companies should measure fair value when they are required to use a fair value measure for recognition or disclosure purposes under GAAP. This Statement addresses the need for increased consistency and comparability in fair value measurements and for expanded disclosures about fair value measurements. The key changes to current practice are: (1) the definition of fair value which focuses on an exit price rather than entry price; (2) the methods used to measure fair value such as emphasis that fair value is a market-based measurement, not an entity-specific measurement, as well as the inclusion of an adjustment for risk, restrictions and credit standing; and (3) the expanded disclosures about fair value measurements. This Statement is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those years. We are currently evaluating the impact of this Statement on its financial statements.

FSP FIN 46(R)-6 – “Determining the Variability to Be Considered in Applying FASB interpretation No. 46(R)”

In April 2006, the FASB issued FSP FIN 46(R)-6 that addresses how a reporting enterprise should determine the variability to be considered in applying FASB interpretation No. 46 (revised December 2003). We adopted FIN 46(R) in the first quarter of 2004, consolidating VIEs when we are determined to be the VIE's primary beneficiary. The variability that is considered in applying interpretation 46(R) affects the determination of (a) whether the entity is a VIE; (b) which interests are variable interests in the entity; and (c) which party, if any, is the primary beneficiary of the VIE. This FSP states that the variability to be considered shall be based on an analysis of the design of the entity, involving two steps:

- Step 1: Analyze the nature of the risks in the entity
- Step 2: Determine the purpose(s) for which the entity was created and determine the variability the entity is designed to create and pass along to its interest holders.

After determining the variability to consider, the reporting enterprise can determine which interests are designed to absorb that variability. The guidance in this FSP is applied prospectively to all entities (including newly created entities) with which that enterprise first becomes involved and to all entities previously required to be analyzed under interpretation 46(R) when a reconsideration event has occurred after July 1, 2006. We do not expect this Statement to have a material impact on our financial statements.

FIN 48 – “Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109”

In June 2006, the FASB issued FIN 48 which clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with FASB Statement No. 109, “Accounting for Income Taxes.” This interpretation prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken on a tax return. This interpretation also provides guidance on derecognition, classification, interest, penalties, accounting in interim periods, disclosure and transition. The evaluation of a tax position in accordance with this interpretation will be a two-step process. The first step will determine if it is more likely than not that a tax position will be sustained upon examination and should therefore be recognized. The second step will measure a tax position that meets the more likely than not recognition threshold to determine the amount of benefit to recognize in the financial statements. This interpretation is effective for fiscal years beginning after December 15, 2006. We do not expect this Statement to have a material impact on our financial statements.

METROPOLITAN EDISON COMPANY
CONSOLIDATED STATEMENTS OF INCOME

<u>For the Years Ended December 31,</u>	<u>2006</u>	<u>2005</u> <i>(In thousands)</i>	<u>2004</u>
REVENUES:			
Electric sales	\$ 1,175,655	\$ 1,113,228	\$ 1,011,947
Gross receipts tax collections	67,403	63,190	58,900
Total revenues	<u>1,243,058</u>	<u>1,176,418</u>	<u>1,070,847</u>
EXPENSES:			
Purchased power (Note 2(I))	634,433	620,764	554,949
Other operating costs (Note 2(I))	304,243	251,442	190,440
Provision for depreciation	41,715	42,684	41,161
Amortization of regulatory assets	115,672	112,117	105,675
Deferral of new regulatory assets	(126,571)	-	-
Goodwill impairment (Note 2(E))	355,100	-	-
General taxes	77,411	73,989	70,457
Total expenses	<u>1,402,003</u>	<u>1,100,996</u>	<u>962,682</u>
OPERATING INCOME (LOSS)	<u>(158,945)</u>	<u>75,422</u>	<u>108,165</u>
OTHER INCOME (EXPENSE):			
Interest income	34,402	36,500	36,140
Miscellaneous income	8,042	8,366	5,646
Interest expense	(47,385)	(44,655)	(45,057)
Capitalized interest	1,017	370	278
Total other income (expense)	<u>(3,924)</u>	<u>581</u>	<u>(2,993)</u>
INCOME (LOSS) BEFORE INCOME TAXES	<u>(162,869)</u>	<u>76,003</u>	<u>105,172</u>
INCOME TAXES	<u>77,326</u>	<u>30,084</u>	<u>38,217</u>
INCOME (LOSS) BEFORE CUMULATIVE EFFECT OF A CHANGE IN ACCOUNTING PRINCIPLE	<u>(240,195)</u>	<u>45,919</u>	<u>66,955</u>
Cumulative effect of a change in accounting principle (net of income tax benefit of \$220,000) (Note 2(G))	<u>-</u>	<u>(310)</u>	<u>-</u>
NET INCOME (LOSS)	<u>\$ (240,195)</u>	<u>\$ 45,609</u>	<u>\$ 66,955</u>

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

METROPOLITAN EDISON COMPANY
CONSOLIDATED BALANCE SHEETS

As of December 31,	2006	2005
	<i>(In thousands)</i>	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	\$ 130	\$ 120
Receivables-		
Customers (less accumulated provisions of \$4,153,000 and \$4,352,000, respectively, for uncollectible accounts)	127,084	129,854
Associated companies	3,604	37,267
Other	8,107	8,780
Notes receivable from associated companies	31,109	27,867
Prepayments and other	14,957	7,912
	184,991	211,800
UTILITY PLANT:		
In service	1,920,563	1,856,425
Less - Accumulated provision for depreciation	739,719	721,566
	1,180,844	1,134,859
Construction work in progress	18,466	20,437
	1,199,310	1,155,296
OTHER PROPERTY AND INVESTMENTS:		
Nuclear plant decommissioning trusts	269,777	234,854
Other	1,362	1,453
	271,139	236,307
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	496,129	864,438
Regulatory assets	409,095	309,556
Prepaid pension costs	7,261	89,005
Other	46,354	51,285
	958,839	1,314,284
	\$ 2,614,279	\$ 2,917,687
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	\$ 50,000	\$ 100,000
Short-term borrowings-		
Associated companies	141,501	140,240
Accounts payable-		
Associated companies	100,232	37,220
Other	59,077	27,507
Accrued taxes	11,300	17,911
Accrued interest	7,496	9,438
Other	22,825	24,274
	392,431	356,590
CAPITALIZATION (See Consolidated Statements of Capitalization):		
Common stockholder's equity	1,014,939	1,316,099
Long-term debt and other long-term obligations	542,009	591,888
	1,556,948	1,907,987
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	387,456	344,929
Accumulated deferred investment tax credits	9,244	10,043
Nuclear fuel disposal costs	41,459	39,567
Asset retirement obligations	151,107	142,020
Retirement benefits	19,599	57,809
Other	56,035	58,742
	664,900	653,110
COMMITMENTS AND CONTINGENCIES (Notes 5 and 11)		
	\$ 2,614,279	\$ 2,917,687

The accompanying Notes to Consolidated Financial Statements are an integral part of these balance sheets.

METROPOLITAN EDISON COMPANY
CONSOLIDATED STATEMENTS OF CAPITALIZATION

<u>As of December 31,</u>	<u>2006</u>	<u>2005</u>
<i>(Dollars in thousands)</i>		
COMMON STOCKHOLDER'S EQUITY:		
Common stock, without par value, 900,000 shares authorized		
859,500 shares outstanding	\$ 1,276,075	\$ 1,287,093
Accumulated other comprehensive loss (Note 2(F))	(26,516)	(1,569)
Retained earnings (Accumulated deficit) (Note 8(A))	<u>(234,620)</u>	<u>30,575</u>
Total	<u>1,014,939</u>	<u>1,316,099</u>
LONG-TERM DEBT (Note 8(C)):		
First mortgage bonds-		
5.950% due 2027	<u>13,690</u>	<u>13,690</u>
Total	<u>13,690</u>	<u>13,690</u>
Unsecured notes-		
5.720% due 2006	-	100,000
5.930% due 2007	50,000	50,000
4.450% due 2010	100,000	100,000
4.950% due 2013	150,000	150,000
4.875% due 2014	250,000	250,000
* 3.800% due 2021	<u>28,500</u>	<u>28,500</u>
Total	<u>578,500</u>	<u>678,500</u>
Net unamortized discount on debt	(181)	(302)
Long-term debt due within one year	<u>(50,000)</u>	<u>(100,000)</u>
Total long-term debt	<u>542,009</u>	<u>591,888</u>
TOTAL CAPITALIZATION	<u>\$ 1,556,948</u>	<u>\$ 1,907,987</u>

* Denotes variable rate issue with applicable year-end interest rate shown.

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

METROPOLITAN EDISON COMPANY

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

	Comprehensive Income (Loss)	Common Stock		Accumulated Other Comprehensive Income (Loss)	Retained Earnings (Accumulated Deficit)
		Number of Shares	Carrying Value		
		<i>(Dollars in thousands)</i>			
Balance, January 1, 2004		859,500	\$ 1,298,130	\$ (32,474)	\$ 27,011
Net income	\$ 66,955				66,955
Net unrealized loss on investments	(26)			(26)	
Net unrealized loss on derivative instruments, net of \$1,279,000 of income tax benefits	(1,819)			(1,819)	
Minimum liability for unfunded retirement benefits, net of \$6,502,000 of income tax benefits	(9,171)			(9,171)	
Comprehensive income	<u>\$ 55,939</u>				
Cash dividends on common stock					(55,000)
Purchase accounting fair value adjustment			(8,187)		
Balance, December 31, 2004		859,500	1,289,943	(43,490)	38,966
Net income	\$ 45,609				45,609
Net unrealized gain on investments, net of \$27,000 of income taxes	39			39	
Net unrealized gain on derivative instruments, net of \$140,000 of income taxes	196			196	
Minimum liability for unfunded retirement benefits, net of \$29,564,000 of income taxes	41,686			41,686	
Comprehensive income	<u>\$ 87,530</u>				
Restricted stock units			28		
Cash dividends on common stock					(54,000)
Purchase accounting fair value adjustment			(2,878)		
Balance, December 31, 2005		859,500	1,287,093	(1,569)	30,575
Net loss	\$ (240,195)				(240,195)
Net unrealized gain on derivative instruments, net of \$139,000 of income taxes	196			196	
Comprehensive loss	<u>\$ (239,999)</u>				
Net liability for unfunded retirement benefits due to the implementation of SFAS 158, net of \$26,715,000 of income tax benefits				(25,143)	
Restricted stock units			50		
Stock based compensation			38		
Cash dividends on common stock					(25,000)
Purchase accounting fair value adjustment			(11,106)		
Balance, December 31, 2006		859,500	\$ 1,276,075	\$ (26,516)	\$ (234,620)

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

METROPOLITAN EDISON COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

<u>For the Years Ended December 31,</u>	<u>2006</u>	<u>2005</u> <i>(In thousands)</i>	<u>2004</u>
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	\$ (240,195)	\$ 45,609	\$ 66,955
Adjustments to reconcile net income (loss) to net cash from operating activities-			
Provision for depreciation	41,715	42,684	41,161
Amortization of regulatory assets	115,672	112,117	105,675
Deferred costs recoverable as regulatory assets	(82,674)	(67,763)	(99,987)
Deferral of new regulatory assets	(126,571)	-	-
Deferred income taxes and investment tax credits, net	50,278	(2,157)	18,495
Accrued compensation and retirement benefits	(6,876)	(5,378)	398
Goodwill impairment	355,100	-	-
Cash collateral to suppliers	(1,580)	-	-
Cumulative effect of a change in accounting principle	-	310	-
Pension trust contributions	-	(35,789)	(38,823)
Decrease (increase) in operating assets-			
Receivables	37,107	77,981	(65,979)
Prepayments and other current assets	(4,385)	3,145	(4,457)
Increase (decrease) in operating liabilities-			
Accounts payable	94,582	(50,249)	35,639
Accrued taxes	(5,647)	5,954	3,195
Accrued interest	(1,804)	(2,180)	(230)
Other	(2,633)	893	11,784
Net cash provided from operating activities	<u>222,089</u>	<u>125,177</u>	<u>73,826</u>
CASH FLOWS FROM FINANCING ACTIVITIES:			
New Financing-			
Long-term debt	-	28,500	247,606
Short-term borrowings, net	1,253	60,150	14,755
Redemptions and Repayments-			
Long-term debt	(100,000)	(66,330)	(196,371)
Dividend Payments-			
Common stock	(25,000)	(54,000)	(55,000)
Net cash provided from (used for) financing activities	<u>(123,747)</u>	<u>(31,680)</u>	<u>10,990</u>
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(84,817)	(85,627)	(52,979)
Proceeds from nuclear decommissioning trust fund sales	182,694	172,018	86,220
Investments in nuclear decommissioning trust funds	(192,177)	(181,501)	(95,703)
Loan repayments from (loans to) associated companies, net	(3,242)	1,355	(8,863)
Other	(790)	258	(13,492)
Net cash used for investing activities	<u>(98,332)</u>	<u>(93,497)</u>	<u>(84,817)</u>
Net change in cash and cash equivalents	10	-	(1)
Cash and cash equivalents at beginning of year	120	120	121
Cash and cash equivalents at end of year	<u>\$ 130</u>	<u>\$ 120</u>	<u>\$ 120</u>
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash Paid During the Year-			
Interest (net of amounts capitalized)	<u>\$ 44,597</u>	<u>\$ 43,266</u>	<u>\$ 43,733</u>
Income taxes (refund)	<u>\$ 42,173</u>	<u>\$ (11,961)</u>	<u>\$ 33,693</u>

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

METROPOLITAN EDISON COMPANY
CONSOLIDATED STATEMENTS OF TAXES

<u>For the Years Ended December 31,</u>	<u>2006</u>	<u>2005</u> <i>(In thousands)</i>	<u>2004</u>
GENERAL TAXES:			
State gross receipts *	\$ 67,403	\$ 63,190	\$ 58,900
Real and personal property	1,893	1,764	1,490
Social security and unemployment	4,135	4,022	3,800
State capital stock	3,946	4,938	6,130
Other	34	75	137
Total general taxes	<u>\$ 77,411</u>	<u>\$ 73,989</u>	<u>\$ 70,457</u>
PROVISION FOR INCOME TAXES:			
Currently payable-			
Federal	\$ 21,046	\$ 24,358	\$ 12,679
State	6,002	7,883	7,043
	<u>27,048</u>	<u>32,241</u>	<u>19,722</u>
Deferred, net-			
Federal	40,075	2,306	20,599
State	11,002	(3,637)	(1,276)
	<u>51,077</u>	<u>(1,331)</u>	<u>19,323</u>
Investment tax credit amortization	(799)	(826)	(828)
Total provision for income taxes	<u>\$ 77,326</u>	<u>\$ 30,084</u>	<u>\$ 38,217</u>
RECONCILIATION OF FEDERAL INCOME TAX EXPENSE AT STATUTORY RATE TO TOTAL PROVISION FOR INCOME TAXES:			
Book income (loss) before provision for income taxes	<u>\$ (162,869)</u>	<u>\$ 76,003</u>	<u>\$ 105,172</u>
Federal income tax expense (benefit) at statutory rate	\$ (57,004)	\$ 26,601	\$ 36,810
Increases (reductions) in taxes resulting from-			
Goodwill impairment	124,285	-	-
Amortization of investment tax credits	(799)	(826)	(828)
Depreciation	3,321	2,203	2,662
State income taxes, net of federal income tax benefit	11,053	2,760	3,749
Other, net	(3,530)	(654)	(4,176)
Total provision for income taxes	<u>\$ 77,326</u>	<u>\$ 30,084</u>	<u>\$ 38,217</u>
ACCUMULATED DEFERRED INCOME TAXES AS OF DECEMBER 31:			
Property basis differences	\$ 276,898	\$ 261,171	\$ 250,643
Deferred sale and leaseback costs	(11,220)	(11,185)	(11,149)
Non-utility generation costs	1,113	1,238	7,475
Purchase accounting basis difference	(642)	(642)	(642)
Sale of generation assets	(1,420)	(1,420)	(1,420)
Nuclear decommissioning	(41,911)	(37,511)	(32,180)
PJM transmission costs	52,519	-	-
Regulatory transition charge	81,924	88,998	95,056
Asset retirement obligations	(237)	(199)	-
Customer receivables for future income taxes	43,960	37,832	40,636
Other comprehensive income	(27,793)	(1,112)	(30,850)
Employee benefits	12,303	9,328	(5,289)
Other	1,962	(1,569)	(6,891)
Net deferred income tax liability	<u>\$ 387,456</u>	<u>\$ 344,929</u>	<u>\$ 305,389</u>

* Collected from customers through regulated rates and included in revenue in the Consolidated Statements of Income.

The Consolidated Statements of Taxes are an integral part of the Notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND BASIS OF PRESENTATION:

The consolidated financial statements include Met-Ed (Company) and its wholly owned subsidiaries. The Company is a wholly owned subsidiary of FirstEnergy. FirstEnergy also holds directly all of the issued and outstanding common shares of its other principal electric utility operating subsidiaries, including OE, CEI, TE, ATSI, JCP&L and Penelec.

The Company follows GAAP and complies with the regulations, orders, policies and practices prescribed by the SEC, PPUC and the FERC. 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 the disclosure of contingent assets and liabilities. Actual results could differ from these estimates.

The Company consolidates all majority-owned subsidiaries over which the Company exercises control and, when applicable, entities for which the Company has a controlling financial interest. Intercompany transactions and balances are eliminated in consolidation. Investments in non-consolidated affiliates (20-50% owned companies, joint ventures and partnerships) over which the Company has the ability to exercise significant influence, but not control, are accounted for on the equity basis.

Certain prior year amounts have been reclassified to conform to the current year presentation. These reclassifications did not change previously reported earnings for 2005 and 2004. All reclassifications have been evaluated and determined to be properly reflected as reclassifications in the respective period as presented in the Consolidated Balance Sheets and Statement of Cash Flows.

Unless otherwise indicated, defined terms used herein have the meanings set forth in the accompanying Glossary of Terms.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

(A) ACCOUNTING FOR THE EFFECTS OF REGULATION-

The Company accounts for the effects of regulation through the application of SFAS 71 since its rates:

- are established by a third-party regulator with the authority to set rates that bind customers;
- are cost-based; and
- can be charged to and collected from customers.

An enterprise meeting all of these criteria capitalizes costs that would otherwise be charged to expense if the rate actions of its regulator make it probable that those costs will be recovered in future revenue. SFAS 71 is applied only to the parts of the business that meet the above criteria. If a portion of the business applying SFAS 71 no longer meets those requirements, previously recorded regulatory assets are removed from the balance sheet in accordance with the guidance in SFAS 101.

Regulatory Assets-

The Company recognizes, as regulatory assets, costs which the FERC and the PPUC have authorized for recovery from customers in future periods or for which authorization is probable. Without the probability of such authorization, costs currently recorded as regulatory assets would have been charged to income as incurred. All regulatory assets are expected to be recovered from customers under the Company's regulatory plan. The Company continues to bill and collect cost-based rates for its transmission and distribution services, which remain regulated; accordingly, it is appropriate that the Company continue the application of SFAS 71 to those operations.

Net regulatory assets on the Consolidated Balance Sheets are comprised of the following:

	<u>2006</u>	<u>2005</u>
	<i>(In millions)</i>	
Regulatory transition costs	\$ 285	\$ 308
Customer receivables for future income taxes	116	100
Nuclear decommissioning costs	(144)	(125)
Employee postretirement benefit costs	12	14
PJM Transmission Costs	127	-
Loss on reacquired debt and other	13	13
Total	<u>\$ 409</u>	<u>\$ 310</u>

Regulatory assets for transition costs as of December 31, 2006 include deferrals associated with the Company's previously divested generation assets and incurred above-market NUG costs. Transition costs and nuclear decommissioning costs are being recovered through CTC revenues. In accordance with the PPUC's January 11, 2007 rate order, PJM transmission costs will be recovered via a transmission service charge rider over ten years. Recovery of the remaining regulatory transition costs is expected to continue under the provisions of the various regulatory proceedings in Pennsylvania.

(B) CASH AND SHORT-TERM FINANCIAL INSTRUMENTS-

All temporary cash investments purchased with an initial maturity of three months or less are reported as cash equivalents on the Consolidated Balance Sheets at cost, which approximates their fair market value.

(C) REVENUES AND RECEIVABLES-

The Company's principal business is providing electric service to customers in Pennsylvania. The Company's retail customers are metered on a cycle basis. Electric revenues are recorded based on energy delivered through the end of the calendar month. An estimate of unbilled revenues is calculated to recognize electric service provided between the last meter reading and the end of the month. This estimate includes many factors including historical customer usage, load profiles, estimated weather impacts, customer shopping activity and prices in effect for each class of customer. In each accounting period, the Company accrues the estimated unbilled amount receivable as revenue and reverses the related prior period estimate.

Receivables from customers include sales to residential, commercial and industrial customers and sales to wholesale customers. There was no material concentration of receivables as of December 31, 2006, with respect to any particular segment of the Company's customers. Total customer receivables were \$127 million (billed – \$70 million and unbilled – \$57 million) and \$130 million (billed – \$78 million and unbilled – \$52 million) as of December 31, 2006 and 2005, respectively.

(D) PROPERTY, PLANT AND EQUIPMENT-

As a result of the Company's acquisition by FirstEnergy in 2001, a portion of the Company's property, plant and equipment was adjusted to reflect fair value. The majority of the Company's property, plant and equipment continues to be reflected at original cost since such assets remain subject to rate regulation on a historical cost basis. The costs of normal maintenance, repairs and minor replacements are expensed as incurred. The Company's accounting policy for planned major maintenance projects is to recognize liabilities as they are incurred.

The Company provides for depreciation on a straight-line basis at various rates over the estimated lives of property included in plant in service. The annualized composite rate was approximately 2.3% in 2006 and 2.4% in 2005 and 2004. The decrease in the composite depreciation rate reflects changes in the depreciable plant base due to assets with higher depreciation rates being fully depreciated since 2002.

(E) ASSET IMPAIRMENTS-

Long-Lived Assets

The Company evaluates the carrying value of its long-lived assets when events or circumstances indicate that the carrying amount may not be recoverable. In accordance with SFAS 144, the carrying amount of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. If an impairment exists, a loss is recognized for the amount by which the carrying value of the long-lived asset exceeds its estimated fair value. Fair value is estimated by using available market valuations or the long-lived asset's expected future net discounted cash flows. The calculation of expected cash flows is based on estimates and assumptions about future events.

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, the Company 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 were indicated, the Company 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. The Company's annual review was completed in the third quarter of 2006, with no impairment of goodwill indicated. The forecasts used in the Company's evaluation of goodwill reflect operations consistent with its general business assumptions. Unanticipated changes in those assumptions could have a significant effect on the Company's future evaluations of goodwill. On January 11, 2007, the PPUC issued its order related to the comprehensive rate filing made by the Company on April 10, 2006. The rate increase granted was substantially lower than the amounts the Company requested. Prior to issuing the order, the PPUC conducted an informal, nonbinding polling of Commissioners at its public meeting on December 21, 2006 that indicated the rate increase ultimately granted would be substantially below the amounts that the Company requested. As a result of the polling, the Company determined that an interim review of goodwill would be required. As a result, the Company recognized an impairment charge of \$355 million in the fourth quarter of 2006. In the year ended December 31, 2006, the Company adjusted goodwill to reverse pre-merger tax accruals due to the final resolution of tax contingencies related to the GPU acquisition. As of December 31, 2006, the Company had approximately \$496 million of goodwill.

Investments

At the end of each reporting period, the Company evaluates for impairment investments that include available-for-sale securities held in its nuclear decommissioning trusts. In accordance with SFAS 115 and FSP SFAS 115-1 and SFAS 124-1 securities classified as available-for-sale are evaluated to determine whether a decline in fair value below the cost basis is other than temporary. The Company first considers its intent and ability to hold the investment until recovery and then considers, among other factors, the duration and the extent to which the security's fair value has been less than cost and the near-term financial prospects of the security issuer when evaluating investments for impairment. If the decline in fair value is determined to be other than temporary, the cost basis of the security is written down to fair value. The recovery of amounts contributed to the Company's decommissioning trusts is subject to regulatory accounting in accordance with SFAS 71. Net unrealized gains and losses are recorded as regulatory liabilities or assets since the difference between investments held in trust and the decommissioning liabilities are recovered from or refunded to customers. The fair value and unrealized gains and losses of the Company's investments are disclosed in Note 4.

(F) COMPREHENSIVE INCOME-

Comprehensive income includes net income as reported on the Consolidated Statements of Income and all other changes in common stockholder's equity excluding the effect from the adoption of SFAS 158 at December 31, 2006, except those resulting from transactions with FirstEnergy. As of December 31, 2006, AOCL consisted of a net liability for unfunded retirement benefits due to the implementation of SFAS 158, net of tax benefits (see Note 3) of \$25 million and unrealized losses on derivative instrument hedges of \$1 million. As of December 31, 2005, AOCL consisted of unrealized losses on derivative instrument hedges of \$2 million.

(G) CUMULATIVE EFFECT OF A CHANGE IN ACCOUNTING PRINCIPLE-

Results in 2005 include an after-tax charge of \$0.3 million recorded upon the adoption of FIN 47 in December 2005. The Company identified applicable legal obligations as defined under the new standard at its substation control rooms, service center buildings, line shops and office buildings, identifying asbestos as the primary conditional ARO. The Company recorded a conditional ARO liability of \$0.6 million (including accumulated accretion for the period from the date the liability was incurred to the date of adoption), an asset retirement cost of \$0.2 million (recorded as part of the carrying amount of the related long-lived asset) and accumulated depreciation of \$0.1 million.

(H) INCOME TAXES-

Details of the total provision for income taxes are shown on the Consolidated Statements of Taxes. The Company records income taxes in accordance with the liability method of accounting. Deferred income taxes reflect the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for tax purposes. Investment tax credits, which were deferred when utilized, are being amortized over the recovery period of the related property. Deferred income tax liabilities related to tax and accounting basis differences and tax credit carryforward items are recognized at the statutory income tax rates in effect when the liabilities are expected to be paid. Deferred tax assets are recognized based on income tax rates expected to be in effect when they are settled. The Company is included in FirstEnergy's consolidated federal income tax return. The consolidated tax liability is allocated on a "stand-alone" company basis, with the Company recognizing the tax benefit for any tax losses or credits it contributes to the consolidated return.

(I) TRANSACTIONS WITH AFFILIATED COMPANIES-

Operating expenses and other income included transactions with affiliated companies, primarily FESC, NGC and FES. FESC provides legal, accounting, financial and other corporate support services to the Company. The Company purchases a portion of its PLR responsibility from FES through a wholesale power sale agreement. The primary affiliated companies' transactions are as follows:

	<u>2006</u>	<u>2005</u>	<u>2004</u>
	<i>(In millions)</i>		
Expenses:			
Power purchased from FES	\$ 178	\$ 348	\$ 434
Service Company support services	51	45	46

FirstEnergy does not bill directly or allocate any of its costs to any subsidiary company. Costs are allocated to the Company from FESC, which is a subsidiary of FirstEnergy. The vast majority of costs are directly billed or assigned at no more than cost. The remaining costs are for services that are provided on behalf of more than one company, or costs that cannot be precisely identified and are allocated using formulas developed by FESC. The current allocation or assignment formulas used and their bases include multiple factor formulas: each company's proportionate amount of FirstEnergy's aggregate direct payroll, number of employees, asset balances, revenues, number of customers, other factors and specific departmental charge ratios. Management believes that these allocation methods are reasonable. Intercompany transactions with FirstEnergy and its other subsidiaries are generally settled under commercial terms within thirty days.

3. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS

FirstEnergy provides noncontributory defined benefit pension plans that cover substantially all of its employees. The trustee plans provide defined benefits based on years of service and compensation levels. FirstEnergy's funding policy is based on actuarial computations using the projected unit credit method. FirstEnergy made a \$300 million voluntary cash contribution to its qualified pension plan on January 2, 2007 (Company's share was \$11 million). Projections indicated that additional cash contributions will not be required before 2016.

FirstEnergy provides a minimum amount of noncontributory life insurance to retired employees in addition to optional contributory insurance. Health care benefits, which include certain employee contributions, deductibles and co-payments, are also available upon retirement to employees hired prior to January 1, 2005, their dependents and, under certain circumstances, their survivors. The Company recognizes the expected cost of providing other postretirement benefits to employees and their beneficiaries and covered dependents from the time employees are hired until they become eligible to receive those benefits. During 2006, FirstEnergy amended the OPEB plan effective in 2008 to cap the monthly contribution for many of the retirees and their spouses receiving subsidized healthcare coverage. In addition, FirstEnergy has obligations to former or inactive employees after employment, but before retirement for disability related benefits.

Pension and OPEB costs are affected by employee demographics (including age, compensation levels, and employment periods), the level of contributions made to the plans and earnings on plan assets. Such factors may be further affected by business combinations which impact employee demographics, plan experience and other factors. Pension and OPEB costs may also be affected by changes in 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 and pension and OPEB costs. FirstEnergy uses a December 31 measurement date for its pension and OPEB plans. The fair value of the plan assets represents the actual market value as of December 31, 2006.

In December 2006, FirstEnergy adopted SFAS 158. This Statement requires an employer to recognize an asset or liability for the overfunded or underfunded status of their pension and other postretirement benefit plans. For a pension plan, the asset or liability is the difference between the fair value of the plan's assets and the projected benefit obligation. For any other postretirement benefit plan, the asset or liability is the difference between the fair value of the plan's assets and the accumulated postretirement benefit obligation. The Statement required employers to recognize all unrecognized prior service costs and credits and unrecognized actuarial gains and losses in AOCL, net of tax. Such amounts will be adjusted as they are subsequently recognized as components of net periodic benefit cost or income pursuant to the current recognition and amortization provisions. Met-Ed's incremental impact of adopting SFAS 158 was a decrease of \$96 million in pension assets, a decrease of \$44 million in pension liabilities and a decrease in AOCL of \$25 million, net of tax.

With the exception of the Company's share of net pension (asset) liability at the end of year and net periodic pension expense, the following tables detail the Consolidated FirstEnergy pension plan and OPEB.

Obligations and Funded Status As of December 31	Pension Benefits		Other Benefits	
	2006	2005	2006	2005
	<i>(In millions)</i>			
Change in benefit obligation				
Benefit obligation as of January 1	\$ 4,750	\$ 4,364	\$ 1,884	\$ 1,930
Service cost	83	77	34	40
Interest cost	266	254	105	111
Plan participants' contributions	-	-	20	18
Plan amendments	3	15	(620)	(312)
Medicare retiree drug subsidy	-	-	6	-
Actuarial (gain) loss	33	310	(119)	197
Benefits paid	(274)	(270)	(109)	(100)
Benefit obligation as of December 31	<u>\$ 4,861</u>	<u>\$ 4,750</u>	<u>\$ 1,201</u>	<u>\$ 1,884</u>
Change in fair value of plan assets				
Fair value of plan assets as of January 1	\$ 4,524	\$ 3,969	\$ 573	\$ 564
Actual return on plan assets	567	325	69	33
Company contribution	-	500	54	58
Plan participants' contribution	-	-	20	18
Benefits paid	(273)	(270)	(109)	(100)
Fair value of plan assets as of December 31	<u>\$ 4,818</u>	<u>\$ 4,524</u>	<u>\$ 607</u>	<u>\$ 573</u>
Funded status	\$ (43)	\$ (226)	\$ (594)	\$ (1,311)
Accumulated benefit obligation	\$ 4,447	\$ 4,327		
Amounts Recognized in the Statement of Financial Position				
Noncurrent assets	\$ -	\$ 1,023	\$ -	\$ -
Current liabilities	-	-	-	-
Noncurrent liabilities	(43)	-	(594)	(1,057)
Net pension asset (liability) at end of year	<u>\$ (43)</u>	<u>\$ 1,023</u>	<u>\$ (594)</u>	<u>\$ (1,057)</u>
Company's share of net pension asset (liability) at end of year	<u>\$ 7</u>	<u>\$ 89</u>	<u>\$ (19)</u>	<u>\$ (57)</u>
Amounts Recognized in Accumulated Other Comprehensive Income				
Prior service cost (credit)	\$ 63	\$ -	\$ (1,190)	\$ -
Actuarial (gain) loss	982	-	702	-
Net amount recognized	<u>\$ 1,045</u>	<u>\$ -</u>	<u>\$ (488)</u>	<u>\$ -</u>
Assumptions Used to Determine Benefit Obligations As of December 31				
Discount rate	6.00%	5.75%	6.00%	5.75%
Rate of compensation increase	3.50%	3.50%		
Allocation of Plan Assets As of December 31				
Asset Category				
Equity securities	64%	63%	72%	71%
Debt securities	29	33	26	27
Real estate	5	2	1	-
Private equities	1	-	-	-
Cash	1	2	1	2
Total	<u>100%</u>	<u>100%</u>	<u>100%</u>	<u>100%</u>

Estimated Items to Be Amortized in 2007 Net Periodic Pension Cost from Accumulated Other Comprehensive Income

	Pension Benefits		Other Benefits	
Prior service cost (credit)	\$	10	\$	(149)
Actuarial (gain) loss	\$	41	\$	45

Components of Net Periodic Benefit Costs	Pension Benefits			Other Benefits		
	2006	2005	2004	2006	2005	2004
	<i>(In millions)</i>					
Service cost	\$ 83	\$ 77	\$ 77	\$ 34	\$ 40	\$ 36
Interest cost	266	254	252	105	111	112
Expected return on plan assets	(396)	(345)	(286)	(46)	(45)	(44)
Amortization of prior service cost	10	8	9	(76)	(45)	(40)
Amortization of transition obligation	-	-	-	-	-	-
Recognized net actuarial loss	58	36	39	56	40	39
Net periodic cost	<u>\$ 21</u>	<u>\$ 30</u>	<u>\$ 91</u>	<u>\$ 73</u>	<u>\$ 101</u>	<u>\$ 103</u>
Company's share of net periodic cost	<u>\$ (7)</u>	<u>\$ (4)</u>	<u>\$ -</u>	<u>\$ 3</u>	<u>\$ 2</u>	<u>\$ 3</u>

Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31

	Pension Benefits			Other Benefits		
	2006	2005	2004	2006	2005	2004
Discount rate	5.75%	6.00%	6.25%	5.75%	6.00%	6.25%
Expected long-term return on plan assets	9.00%	9.00%	9.00%	9.00%	9.00%	9.00%
Rate of compensation increase	3.50%	3.50%	3.50%			

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. The assumed rates of return on pension plan assets consider historical market returns and economic forecasts for the types of investments held by the Company's pension trusts. The long-term rate of return is developed considering the portfolio's asset allocation strategy.

FirstEnergy employs a total return investment approach whereby a mix of equities and fixed income investments are used to maximize the long-term return on plan assets for a prudent level of risk. Risk tolerance is established through careful consideration of plan liabilities, plan funded status, and corporate financial condition. The investment portfolio contains a diversified blend of equity and fixed-income investments. Furthermore, equity investments are diversified across U.S. and non-U.S. stocks, as well as growth, value, and small and large capitalization funds. Other assets such as real estate are used to enhance long-term returns while improving portfolio diversification. Derivatives may be used to gain market exposure in an efficient and timely manner; however, derivatives are not used to leverage the portfolio beyond the market value of the underlying investments. Investment risk is measured and monitored on a continuing basis through periodic investment portfolio reviews, annual liability measurements, and periodic asset/liability studies.

Assumed Health Care Cost Trend Rates As of December 31

	2006	2005
Health care cost trend rate assumed for next year (pre/post-Medicare)	9-11%	9-11%
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	5%	5%
Year that the rate reaches the ultimate trend rate (pre/post-Medicare)	2011-2013	2010-2012

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	1-Percentage-Point Increase		1-Percentage-Point Decrease	
	<i>(In millions)</i>			
Effect on total of service and interest cost	\$	6	\$	(5)
Effect on accumulated postretirement benefit obligation	\$	33	\$	(29)

Taking into account estimated employee future service, FirstEnergy expects to make the following benefit payments from plan assets:

	<u>Pension Benefits</u>	<u>Other Benefits</u>
	<i>(In millions)</i>	
2007	\$ 247	\$ 91
2008	249	91
2009	256	94
2010	269	98
2011	280	101
Years 2012- 2016	1,606	537

4. FAIR VALUE OF FINANCIAL INSTRUMENTS:

(A) LONG-TERM DEBT-

All borrowings with initial maturities of less than one year are defined as financial instruments under GAAP and are reported on the Consolidated Balance Sheets at cost, which approximates their fair market value. The following table provides the approximate fair value and related carrying amounts of long-term debt as disclosed in the Consolidated Statements of Capitalization as of December 31:

	<u>2006</u>		<u>2005</u>	
	<u>Carrying Value</u>	<u>Fair Value</u>	<u>Carrying Value</u>	<u>Fair Value</u>
	<i>(In millions)</i>			
Long-term debt	\$ 592	\$ 572	\$ 692	\$ 683

The fair value of long-term debt reflects the present value of the cash outflows relating to those securities based on the current call price, the yield to maturity or the yield to call, as deemed appropriate at the end of each respective year. The yields assumed were based on securities with similar characteristics offered by corporations with credit ratings similar to the Company's ratings.

(B) NUCLEAR DECOMMISSIONING TRUSTS-

Nuclear decommissioning trust investments are classified as available-for-sale securities. The Company has no securities held for trading purposes. The Company periodically evaluates the securities held by its nuclear decommissioning trusts for other-than-temporary impairment. The Company first considers its intent and ability to hold the investment until recovery and then considers, among other factors, the duration and the extent to which the security's fair value has been less than cost and financial condition and the near-term financial prospects of the security issuer when evaluating investments for impairment. The following table provides the approximate fair value and related carrying amounts of the nuclear decommissioning trust and excludes \$1 million for both 2006 and 2005 of other investments excluded by SFAS 107, "Disclosures about Fair Values of Financial Instruments", as of December 31:

	<u>2006</u>	<u>2005</u>
	<i>(In millions)</i>	
Debt securities		
-Government Obligations	\$ 97	\$ 87
-Corporate debt securities	9	6
	<u>106</u>	<u>93</u>
Equity securities	164	142
	<u>\$ 270</u>	<u>\$ 235</u>

The following table summarizes the amortized cost basis, gross unrealized gains and losses and fair values for nuclear decommissioning trust investments as of December 31:

	2006				2005			
	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
	<i>(In millions)</i>							
Debt securities	\$ 105	\$ 1	\$ -	\$ 106	\$ 92	\$ 2	\$ 1	\$ 93
Equity securities	114	50	-	164	113	30	1	142
	<u>\$ 219</u>	<u>\$ 51</u>	<u>\$ -</u>	<u>\$ 270</u>	<u>\$ 205</u>	<u>\$ 32</u>	<u>\$ 2</u>	<u>\$ 235</u>

Proceeds from the sale of nuclear decommissioning trust investments, gross realized gains and losses on those sales, and interest and dividend income for the three years ended December 31, 2006 were as follows:

	2006	2005	2004
	<i>(In millions)</i>		
Proceeds from sales	\$ 170	\$ 138	\$ 179
Gross realized gains	1	6	30
Gross realized losses	4	7	1
Interest and dividend income	7	6	6

The recovery of amounts contributed to the Company's nuclear decommissioning trusts are subject to regulatory accounting in accordance with SFAS 71. Net unrealized gains and losses are recorded as regulatory liabilities or assets since the difference between investments held in trust and the nuclear decommissioning liabilities will be recovered from or refunded to customers.

The investment policy for the nuclear decommissioning trust funds restricts or limits the ability to hold certain types of assets including private or direct placements, warrants, securities of FirstEnergy, investments in companies owning nuclear power plants, financial derivatives, preferred stocks, securities convertible into common stock and securities of the trust fund's custodian or managers and their parents or subsidiaries.

5. LEASES:

Consistent with the regulatory treatment, the rentals for operating leases are charged to operating expenses on the Consolidated Statements of Income. The Company's most significant operating leases relate to the sale and leaseback of a portion of its ownership interest in the Merrill Creek Reservoir project and the lease of vehicles.

Such costs for the three years ended December 31, 2006 are summarized as follows:

	2006	2005	2004
	<i>(In millions)</i>		
Operating leases			
Interest element	\$ 2.0	\$ 1.9	\$ 1.8
Other	1.5	1.0	1.1
Total rentals	<u>\$ 3.5</u>	<u>\$ 2.9</u>	<u>\$ 2.9</u>

The future minimum lease payments as of December 31, 2006 are:

	Operating Leases
	<i>(In millions)</i>
2007	\$ 4.0
2008	3.9
2009	4.2
2010	4.0
2011	3.6
Years thereafter	45.8
Total minimum lease payments	<u>\$ 65.5</u>

6. VARIABLE INTEREST ENTITIES:

FIN 46R addresses the consolidation of VIEs, including special-purpose entities, that are not controlled through voting interests or in which the equity investors do not bear the entity's residual economic risks and rewards. FirstEnergy adopted FIN 46R for special-purpose entities as of December 31, 2003 and for all other entities in the first quarter of 2004. The Company consolidates a VIE when it is determined to be the VIE's primary beneficiary as defined by FIN 46R.

The Company 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 Company and the contract price for power is correlated with the plant's variable costs of production. The Company maintains several long-term power purchase agreements with NUG entities. The agreements were structured pursuant to the Public Utility Regulatory Policies Act of 1978. The Company was not involved in the creation of, and has no equity or debt invested in, these entities.

The Company has determined that for all but one of these entities, the Company has no variable interests in the entities or the entities are governmental or not-for-profit organizations not within the scope of FIN 46R. The Company may hold a variable interest in the remaining entity, which sells its output at variable price that correlates to some extent with the operating costs of the plant. As required by FIN 46R, the Company periodically requests the information necessary from this entity to determine whether it is a VIE or whether the Company is the primary beneficiary. The Company has been unable to obtain the requested information, which was deemed by the requested entity to be proprietary. As such, the Company applied the scope exception that exempts enterprises unable to obtain the necessary information to evaluate entities under FIN 46R. As of December 31, 2006, the below-market loss liability recognized for this NUG agreement was \$121 million. The purchased power costs from this entity during 2006, 2005, and 2004 were \$60 million, \$50 million, and \$54 million, respectively.

7. REGULATORY MATTERS:

In late 2003 and early 2004, a series of letters, reports and recommendations were issued from various entities, including governmental, industry and ad hoc reliability entities (PUCO, FERC, NERC and the U.S. – Canada Power System Outage Task Force) regarding enhancements to regional reliability. In 2004, FirstEnergy completed implementation of all actions and initiatives related to enhancing area reliability, improving voltage and reactive management, operator readiness and training and emergency response preparedness recommended for completion in 2004. On July 14, 2004, NERC independently verified that FirstEnergy had implemented the various initiatives to be completed by June 30 or summer 2004, with minor exceptions noted by FirstEnergy, which exceptions are now essentially complete. FirstEnergy is proceeding with the implementation of the recommendations that were to be completed subsequent to 2004 and will continue to periodically assess the FERC-ordered Reliability Study recommendations for forecasted 2009 system conditions, recognizing revised load forecasts and other changing system conditions which may impact the recommendations. Thus far, implementation of the recommendations has not required, nor is expected to require, substantial investment in new equipment or material upgrades to existing equipment. The FERC or other applicable government agencies and reliability entities may, however, take a different view as to recommended enhancements or may recommend additional enhancements in the future, which could require additional, material expenditures.

The EPACT provides for the creation of an ERO to establish and enforce reliability standards for the bulk power system, subject to FERC's review. On February 3, 2006, the FERC adopted a rule establishing certification requirements for the ERO, as well as regional entities envisioned to assume compliance monitoring and enforcement responsibility for the new reliability standards. The FERC issued an order on rehearing on March 30, 2006, providing certain clarifications and essentially affirming the rule.

The NERC has been preparing the implementation aspects of reorganizing its structure to meet the FERC's certification requirements for the ERO. The NERC made a filing with the FERC on April 4, 2006 to obtain certification as the ERO and to obtain FERC approval of pro forma delegation agreements with regional reliability organizations (regional entities). The new FERC rule referred to above, further provides for reorganizing regional entities that would replace the current regional councils and for rearranging their relationship with the ERO. The "regional entity" may be delegated authority by the ERO, subject to FERC approval, for compliance and enforcement of reliability standards adopted by the ERO and approved by the FERC. The ERO filing was noticed on April 7, 2006 and comments and reply comments were filed in May, June and July 2006. On July 20, 2006, the FERC certified the NERC as the ERO to implement the provisions of Section 215 of the Federal Power Act and directed the NERC to make compliance filings addressing governance and non-governance issues and the regional delegation agreements. On September 18, 2006 and October 18, 2006, NERC submitted compliance filings addressing the governance and non-governance issues identified in the FERC ERO Certification Order, dated July 20, 2006. On October 30, 2006, the FERC issued an order accepting most of NERC's governance filings. On January 18, 2007, the FERC issued an order largely accepting NERC's compliance filings addressing non-governance issues, subject to an additional compliance filing requirement.

On April 4, 2006, NERC also submitted a filing with the FERC seeking approval of mandatory reliability standards, as well as for approval with the relevant Canadian authorities. These reliability standards are based, with some modifications and additions, on the current NERC Version 0 reliability standards. The reliability standards filing was subsequently evaluated by the FERC on May 11, 2006, leading to the FERC staff's release of a preliminary assessment that cited many deficiencies in the proposed reliability standards. The NERC and industry participants filed comments in response to the Staff's preliminary assessment. The FERC held a technical conference on the proposed reliability standards on July 6, 2006. The FERC issued a NOPR on the proposed reliability standards on October 20, 2006. In the NOPR, the FERC proposed to approve 83 of the 107 reliability standards and directed NERC to make technical improvements to 62 of the 83 standards approved. The 24 standards that were not approved remain pending at the FERC awaiting further clarification and filings by the NERC and regional entities. The FERC also provided additional clarification within the NOPR regarding the proposed application of final standards and guidance with regard to technical improvements of the standards. On November 15, 2006, NERC submitted several revised reliability standards and three new proposed reliability standards. Interested parties were provided the opportunity to comment on the NOPR (including the revised standards submitted by NERC in November) by January 3, 2007. Numerous parties, including FirstEnergy, filed comments on the NOPR on January 3, 2007. Mandatory reliability standards enforceable with penalties are expected to be in place by the summer of 2007. In a separate order issued October 24, 2006, the FERC approved NERC's 2007 budget and business plan subject to certain compliance filings.

On November 29, 2006, NERC submitted an additional compliance filing with the FERC regarding the Compliance Monitoring and Enforcement Program (CMEP) along with the proposed Delegation Agreements between the ERO and the regional reliability entities. The FERC provided opportunity for interested parties to comment on the CMEP by January 10, 2007. We, as well as other parties, moved to intervene and submitted responsive comments on January 10, 2007. This filing is pending before the FERC.

The ECAR, Mid-Atlantic Area Council, and Mid-American Interconnected Network reliability councils completed the consolidation of these regions into a single new regional reliability organization known as ReliabilityFirst Corporation. ReliabilityFirst began operations as a regional reliability council under NERC on January 1, 2006 and on November 29, 2006 filed a proposed Delegation Agreement with NERC to obtain certification consistent with the final rule as a "regional entity" under the ERO. All of FirstEnergy's facilities are located within the ReliabilityFirst region.

On May 2, 2006, the NERC Board of Trustees adopted eight new cyber security standards that replaced interim standards put in place in the wake of the September 11, 2001 terrorist attacks, and thirteen additional reliability standards. The security standards became effective on June 1, 2006, and the remaining standards will become effective throughout 2006 and 2007. NERC filed these proposed standards with the FERC and relevant Canadian authorities for approval. The cyber security standards were not included in the October 20, 2006 NOPR and are being addressed in a separate FERC docket. On December 11, 2006, the FERC Staff provided its preliminary assessment of these proposed mandatory reliability standards and again cited various deficiencies in the proposed standards, providing interested parties with the opportunity to comment on the assessment by February 12, 2007.

FirstEnergy believes it is in compliance with all current NERC reliability standards. However, based upon a review of the October 20, 2006 NOPR, it appears that the FERC will adopt more strict reliability standards than those contained in the current NERC standards. The financial impact of complying with the new standards cannot be determined at this time. However, the EPACT required that all prudent costs incurred to comply with the new reliability standards be recovered in rates. If FirstEnergy is unable to meet the reliability standards for its bulk power system in the future, it could have a material adverse effect on FirstEnergy's and its subsidiaries' financial condition, results of operations and cash flows.

A February 2002 Commonwealth Court of Pennsylvania decision affirmed the June 2001 PPUC decision regarding approval of the FirstEnergy/GPU merger, remanded the issues of quantification and allocation of merger savings to the PPUC and denied the Company's the rate relief initially approved in the PPUC decision. On May 4, 2006, the PPUC consolidated the merger savings proceeding with the April 10, 2006 comprehensive rate filing proceeding discussed below. On January 11, 2007, the PPUC entered an order in that rate filing proceeding and determined that no merger savings from prior years should be considered in determining customers' rates.

On January 12, 2005, the Company filed, before the PPUC, a request for deferral of transmission-related costs beginning January 1, 2005. The company sought to consolidate this proceeding (and modified its request to provide deferral of 2006 transmission-related costs only) with the comprehensive rate filing made on April 10, 2006, described below. On May 4, 2006, the PPUC approved the modified request.

The Company has been purchasing a portion of its PLR requirements from FES through a partial requirements wholesale power sales agreement and various amendments. Under these agreements, FES retained the supply obligation and the supply profit and loss risk for the portion of power supply requirements not self-supplied by the Company. The FES agreements have reduced the Company's exposure to high wholesale power prices by providing power at a fixed price for its uncommitted PLR capacity and energy costs during the term of these agreements with FES.

On April 7, 2006, the parties entered into a Tolling Agreement that arose from FES' notice to the Company that FES elected to exercise its right to terminate the partial requirements agreement effective midnight December 31, 2006. On November 29, 2006, the Company and FES agreed to suspend the April 7 Tolling Agreement pending resolution of the PPUC's proceedings regarding the Company's Transition Rate cases filed April 10, 2006, described below. Separately, on September 26, 2006, the Company successfully conducted a competitive RFP for a portion of its PLR obligation for the period December 1, 2006 through December 31, 2008. FES was one of the successful bidders in that RFP process and on September 26, 2006 entered into a Supplier Master Agreement to supply a certain portion of the Company's PLR requirements at market prices that substantially exceed the fixed price in the partial requirements agreements.

Based on the outcome of the Transition Rate filing, as described below, the Company and FES agreed to restate the partial requirements power sales agreement effective January 1, 2007. The restated agreement incorporates the same fixed price for residual capacity and energy supplied by FES as in the prior arrangements between the parties, and automatically extends for successive one year terms unless any party gives 60 days' notice prior to the end of the year. The restated agreement allows the Company to sell the output of NUG generation to the market and requires FES to provide energy at fixed prices to replace any NUG energy thus sold to the extent needed for the Company to satisfy its PLR obligations. The parties have also separately terminated the Tolling, Suspension and Supplier Master agreements in connection with the restatement of the partial requirements agreement. Accordingly, the energy that would have been supplied under the Master Supplier Agreement will now be provided under the restated partial requirements agreement.

If the Company were to replace the entire FES supply at current market power prices without corresponding regulatory authorization to increase its generation prices to customers, the Company would likely incur a significant increase in operating expenses and experience a material deterioration in credit quality metrics. Under such a scenario, the Company's credit profile would no longer be expected to support an investment grade rating for its fixed income securities. Based on the PPUC's January 11, 2007 order described below, if FES ultimately determines to terminate, reduce, or significantly modify the agreement prior to the expiration of the Company's generation rate caps in 2010, timely regulatory relief is not likely to be granted by the PPUC.

The Company made a comprehensive rate filing with the PPUC on April 10, 2006 to address a number of transmission, distribution and supply issues. If the Company's preferred approach involving accounting deferrals was approved, the filing would have increased annual revenues by \$216 million. That filing included, among other things, a request to charge customers for an increasing amount of market priced power procured through a CBP as the amount of supply provided under the then existing FES agreement is phased out in accordance with the April 7, 2006 Tolling Agreement described above. The Company also requested approval of the January 12, 2005 petition for the deferral of transmission-related costs discussed above, but only for those costs incurred during 2006. In this rate filing, the Company also requested recovery of annual transmission and related costs incurred on or after January 1, 2007, plus the amortized portion of 2006 costs over a ten-year period, along with applicable carrying charges, through an adjustable rider similar to that implemented in Ohio. Changes in the recovery of NUG expenses and the recovery of the Company's non-NUG stranded costs were also included in the filing. Hearings were held in late August 2006 and briefing occurred in September and October. The ALJs issued their Recommended Decision on November 2, 2006.

The PPUC entered its Opinion and Order in the rate filing proceeding on January 11, 2007. The Order approved the recovery of transmission costs, including the 2006 deferral, and determined that no merger savings from prior years should be considered in determining customers' rates. The request for increases in generation supply rates was denied as were the requested changes in NUG expense recovery and the Company's non-NUG stranded costs. The order decreased the Company's distribution rates by \$80 million. The company's request for recovery of Saxton decommissioning costs was granted. In January 2007, the company recognized income of \$16 million to establish a regulatory asset for the previously expensed decommissioning costs. These decreases were offset by the increases allowed for the recovery of transmission expenses and the 2006 transmission deferral. The Company's overall rates increased by 5.0% or \$59 million. The Company filed a Petition for Reconsideration on January 26, 2007 on the issues of consolidated tax savings and rate of return on equity. Other parties filed Petitions for Reconsideration on transmission congestion, transmission deferrals and rate design issues. The PPUC on February 8, 2007 entered an order granting Met-Ed's, Penelec's and the other parties' petitions for procedural purposes. Due to that ruling, the period for appeals to the Commonwealth Court is tolled until 30 days after the PPUC enters a subsequent order ruling on the substantive issues raised in the petitions.

As of December 31, 2006, the Company's regulatory deferrals pursuant to the 1998 Restructuring Settlement (including the Phase 2 Proceedings) and the FirstEnergy/GPU Merger Settlement Stipulation were \$303 million. During the PPUC's annual audit of the Company's NUG stranded cost balances in 2006, it noted a modification to the Company's NUG purchased power stranded cost accounting methodology. On August 18, 2006, a PPUC Order was entered requiring the Company to reflect the deferred NUG cost balances as if the stranded cost accounting methodology modification had not been implemented. As a result of the PPUC's Order, the Company recognized a pre-tax charge of approximately \$10.3 million in the third quarter of 2006, representing incremental costs deferred under the revised methodology in 2005. The Company continues to believe that the stranded cost accounting methodology modification is appropriate and on August 24, 2006 filed a petition with the PPUC pursuant to its Order for authorization to reflect the stranded cost accounting methodology modification effective January 1, 1999. Hearings on this petition are scheduled for late February 2007. It is not known when the PPUC may issue a final decision in this matter.

On February 1, 2007 the Governor of Pennsylvania proposed an Energy Independence Strategy (EIS). The EIS includes four pieces of preliminary draft legislation that, according to the Governor, is designed to reduce energy costs, promote energy independence and stimulate the economy. Elements of the EIS include the installation of smart meters, funding for solar panels on residences and small businesses, conservation programs to meet demand growth, a requirement that electric distribution companies acquire power through a "Least Cost Portfolio", the utilization of micro-grids and a three year phase-in of rate increases. Since the EIS has only recently been proposed, the final form of any legislation is uncertain. Consequently, FirstEnergy is unable to predict what impact, if any, such legislation may have on its operations.

On November 18, 2004, the FERC issued an order eliminating the RTOR for transmission service between the MISO and PJM regions. The FERC also ordered the MISO, PJM and the transmission owners within MISO and PJM to submit compliance filings containing a SECA mechanism to recover lost RTOR revenues during a 16-month transition period from load serving entities. The FERC issued orders in 2005 setting the SECA for hearing. ATSI, JCP&L, the Company, Penelec, and FES participated in the FERC hearings held in May 2006 concerning the calculation and imposition of the SECA charges. The Presiding Judge issued an Initial Decision on August 10, 2006, rejecting the compliance filings made by the RTOs and transmission owners, ruling on various issues and directing new compliance filings. This decision is subject to review and approval by the FERC. Briefs addressing the Initial Decision were filed on September 11, 2006 and October 20, 2006. A final order could be issued by the FERC in early 2007.

On January 31, 2005, certain PJM transmission owners made three filings with the FERC pursuant to a settlement agreement previously approved by the FERC. JCP&L, the Company and Penelec were parties to that proceeding and joined in two of the filings. In the first filing, the settling transmission owners submitted a filing justifying continuation of their existing rate design within the PJM RTO. In the second filing, the settling transmission owners proposed a revised Schedule 12 to the PJM tariff designed to harmonize the rate treatment of new and existing transmission facilities. Interventions and protests were filed on February 22, 2005. In the third filing, Baltimore Gas and Electric Company and Pepco Holdings, Inc. requested a formula rate for transmission service provided within their respective zones. On May 31, 2005, the FERC issued an order on these cases. First, it set for hearing the existing rate design and indicated that it will issue a final order within six months. American Electric Power Company, Inc. filed in opposition proposing to create a "postage stamp" rate for high voltage transmission facilities across PJM. Second, the FERC approved the proposed Schedule 12 rate harmonization. Third, the FERC accepted the proposed formula rate, subject to refund and hearing procedures. On June 30, 2005, the settling PJM transmission owners filed a request for rehearing of the May 31, 2005 order. On March 20, 2006, a settlement was filed with FERC in the formula rate proceeding that generally accepts the companies' formula rate proposal. The FERC issued an order approving this settlement on April 19, 2006. Hearings in the PJM rate design case concluded in April 2006. On July 13, 2006, an Initial Decision was issued by the ALJ. The ALJ adopted the FERC Trial Staff's position that the cost of all PJM transmission facilities should be recovered through a postage stamp rate. The ALJ recommended an April 1, 2006 effective date for this change in rate design. If the FERC accepts this recommendation, the transmission rate applicable to many load zones in PJM would increase. FirstEnergy believes that significant additional transmission revenues would have to be recovered from the JCP&L, Met-Ed and Penelec transmission zones within PJM. JCP&L, the Company and Penelec, as part of the Responsible Pricing Alliance, filed a brief addressing the Initial Decision on August 14, 2006 and September 5, 2006. The case will be reviewed by the FERC with a decision anticipated in early 2007.

On February 16, 2007, the FERC issued a final rule that revises its decade-old open access transmission regulations and policies. The FERC explained that the final rule is intended to strengthen non-discriminatory access to the transmission grid, facilitate FERC enforcement, and provide for a more open and coordinated transmission planning process. The final rule will not be effective until 60 days after publication in the Federal Register. The final rule has not yet been fully evaluated to assess its impact on our operations.

8. CAPITALIZATION:

(A) ACCUMULATED DEFICIT-

In general, the Company's first mortgage indenture restricts the payment of dividends or distributions on or with respect to the Company's common stock to amounts credited to earned surplus since the date of its indenture. The Company had an accumulated deficit of \$235 million as of December 31, 2006, and is therefore restricted from making cash dividend distributions to FirstEnergy.

(B) PREFERRED AND PREFERENCE STOCK-

The Company's preferred stock authorization consists of 10 million shares without par value. No preferred shares are currently outstanding.

(C) LONG-TERM DEBT-

The Company's first mortgage indenture, which secures all of the Company's FMB, serves as a direct first mortgage lien on substantially all of the Company's property and franchises, other than specifically excepted property.

The Company has various debt covenants under its financing arrangements. The most restrictive of these relate to the nonpayment of interest and/or principal on debt, which could trigger a default. Cross-default provisions also exist between FirstEnergy and the Company.

Based on the amount of bonds authenticated by the Trustee through December 31, 2006, the Company's annual sinking fund requirements for all bonds issued under the mortgage amount to \$18 million. The Company could fulfill its sinking fund obligation by providing refundable bonds, property additions or cash to the Trustee.

Sinking fund requirements for FMB and maturing long-term debt for the next five years are:

	<i>(In millions)</i>
2007	\$ 50
2008	-
2009	-
2010	100
2011	-

The Company's obligations to repay certain pollution control revenue bonds are secured by a series of FMB. Certain pollution control revenue bonds are entitled to the benefit of noncancelable municipal bond insurance policies of \$42 million to pay principal of, or interest on, the pollution control revenue bonds. To the extent that drawings are made under the policies, the Company is entitled to a credit against its obligation to repay that bond. For the pollution control revenue bonds issued in 2005, the Company pays annual fees of 0.16% of the amount of the policy to the insurer. The Company is obligated to reimburse the insurers for any drawings thereunder.

9. ASSET RETIREMENT OBLIGATIONS

Met-Ed has recognized legal obligations under SFAS 143 for nuclear plant decommissioning. In addition, the Company has recognized conditional retirement obligations (primarily for asbestos remediation) in accordance with FIN 47, which was implemented on December 31, 2005. SFAS 143 requires recognition of the fair value of a liability for an ARO in the period in which it is incurred. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. Over time the capitalized costs are depreciated and the present value of the ARO increases, resulting in a period expense. However, rate-regulated entities may recognize a regulatory asset or liability instead of an expense if the criteria for such treatment are met. Upon retirement, a gain or loss would be recognized if the cost to settle the retirement obligation differs from the carrying amount.

The ARO liability of \$151 million as of December 31, 2006 primarily relates to the nuclear decommissioning of TMI-2. The obligation to decommission this unit was developed based on site specific studies performed by an independent engineer. The Company uses an expected cash flow approach to measure the fair value of the nuclear decommissioning ARO.

The Company maintains the nuclear decommissioning trust funds that are legally restricted for purposes of settling the nuclear decommissioning ARO. As of December 31, 2006, the fair value of the decommissioning trust assets was \$270 million.

FIN 47 provides accounting standards for conditional retirement obligations associated with tangible long-lived assets, requiring recognition of the fair value of a liability for an ARO in the period in which it is incurred if a reasonable estimate can be identified. FIN 47 states that an obligation exists even though there may be uncertainty about timing or method of settlement and further clarifies SFAS 143, stating that the uncertainty surrounding the timing and method of settlement when settlement is conditional on a future event occurring should be reflected in the measurement of the liability not in the recognition of the liability. Accounting for conditional ARO under FIN 47 is the same as described above for SFAS 143.

The Company identified applicable legal obligations as defined under the new standard at its hydroelectric generation facilities, substation control rooms, service center buildings, line shops and office buildings, identifying asbestos as the primary conditional ARO. As a result of adopting FIN 47 in December 2005, the Company recorded a conditional ARO liability of \$0.6 million (including accumulated accretion for the period from the date the liability was incurred to the date of adoption), an asset retirement cost of \$0.2 million (recorded as part of the carrying amount of the related long-lived asset) and accumulated depreciation of \$0.1 million. As a result, the Company recorded a \$0.5 million cumulative effect adjustment (\$0.3 million, net of tax) for unrecognized depreciation and accretion as of December 31, 2005. The costs of remediation were based on costs incurred during recent remediation projects performed at each of these locations. The conditional ARO liability was developed utilizing an expected cash flow approach (as discussed in SFAC 7) to measure the fair value of the ARO. The Company used a probability weighted analysis to estimate when remediation payments would begin. The effect on income as if FIN 47 had been applied during 2004 was immaterial.

The following table describes the changes to the ARO balances during 2006 and 2005:

ARO Reconciliation	2006	2005
	<i>(In millions)</i>	
Balance at beginning of year	\$ 142	\$ 133
Accretion	9	8
FIN 47 ARO upon adoption	-	1
Balance at end of year	\$ 151	\$ 142

10. SHORT-TERM BORROWINGS:

Short-term borrowings outstanding as of December 31, 2006, consisted of \$142 million of borrowings from affiliates. Met-Ed Funding, a wholly owned subsidiary of the Company, is a limited liability company whose borrowings are secured by customer accounts receivable purchased from the Company. It can borrow up to \$80 million under a receivables financing arrangement at rates based on certain bank commercial paper and is required to pay an annual facility fee is 0.13% on the entire finance limit. This financing arrangement expires on June 28, 2007. As a separate legal entity with separate creditors, it would have to satisfy its obligations to creditors before any of its remaining assets could be made available to the Company. As of December 31, 2006, the facility was not drawn.

On August 24, 2006, the Company, FirstEnergy, OE, Penn, CEI, TE, JCP&L, Penelec, FES and ATSI, as Borrowers, entered into a new \$2.75 billion five-year revolving credit facility, which replaced the prior \$2 billion credit facility. Subject to specified conditions, FirstEnergy may request an increase in the total commitments available under the new facility up to a maximum of \$3.25 billion. Commitments under the new facility are available until August 24, 2011, unless the lenders agree, at the request of the Borrowers, to two additional one-year extensions. Generally, borrowings under the facility must be repaid within 364 days. Available amounts for each Borrower are subject to a specified sublimit, as well as applicable regulatory and other limitations. The Company's borrowing limit under the facility is \$250 million. The average interest rate on short-term borrowings outstanding as of December 31, 2006 and 2005 was 5.6% and 4.0%, respectively.

11. COMMITMENTS, GUARANTEES AND CONTINGENCIES:

(A) NUCLEAR INSURANCE-

The Price-Anderson Act limits the public liability relative to a single incident at a nuclear power plant to \$10.8 billion. The amount is covered by a combination of private insurance and an industry retrospective rating plan. Based on its present ownership interest in TMI-2, the Company is exempt from any potential assessment under the industry retrospective rating plan.

The Company is also insured as to its interest in TMI-2 under a policy issued to the operating company for the plant. Under this policy, \$150 million is provided for property damage and decontamination and decommissioning costs. Under this policy, the Company can be assessed a maximum of approximately \$0.4 million for incidents at any covered nuclear facility occurring during a policy year which are in excess of accumulated funds available to the insurer for paying losses.

The Company intends to maintain insurance against nuclear risks as described above as long as it is available. To the extent that property damage, decontamination, decommissioning, repair and replacement costs and other such costs arising from a nuclear incident at TMI-2 exceed the policy limits of the insurance in effect with respect to that plant, to the extent a nuclear incident is determined not to be covered by the Company's insurance policies, or to the extent such insurance becomes unavailable in the future, the Company would remain at risk for such costs.

(B) ENVIRONMENTAL MATTERS-

The Company accrues environmental liabilities only when it concludes that it is probable that we have an obligation for such costs and can reasonably estimate the amount of such costs. Unasserted claims are reflected in our determination of environmental liabilities and are accrued in the period that they become both probable and reasonably estimable.

The Company has been named as a PRP 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 December 31, 2006, based on estimates of the total costs of cleanup, the Company's proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. Total liabilities of approximately \$48,000 have been accrued through December 31, 2006.

(C) OTHER LEGAL PROCEEDINGS-

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. The U.S. – Canada Power System Outage Task Force's final report in April 2004 on the outages concluded, among other things, that the problems leading to the outages began in FirstEnergy's Ohio service area. Specifically, the final report concluded, 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 real-time diagnostic support. The final report is publicly available through the Department of Energy's Web site (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 contained 46 "recommendations to prevent or minimize the scope of future blackouts." Forty-five of those recommendations related to broad industry or policy matters while one, including subparts, related to activities the Task Force recommended be undertaken by FirstEnergy, MISO, PJM, ECAR, and other parties to correct the causes of the August 14, 2003 power outages. FirstEnergy implemented several initiatives, both prior to and since the August 14, 2003 power outages, which were independently verified by NERC as complete in 2004 and were consistent with these and other recommendations and collectively enhance the reliability of its electric system. FirstEnergy's implementation of these recommendations in 2004 included completion of the Task Force recommendations that were directed toward FirstEnergy. FirstEnergy is also proceeding with the implementation of the recommendations that were to be completed subsequent to 2004 and will continue to periodically assess the FERC-ordered Reliability Study recommendations for forecasted 2009 system conditions, recognizing revised load forecasts and other changing system conditions which may impact the recommendations. Thus far, implementation of the recommendations has not required, nor is expected to require, substantial investment in new or material upgrades to existing equipment. The FERC or other applicable government agencies and reliability coordinators may, however, take a different view as to recommended enhancements or may recommend additional enhancements in the future that could require additional material expenditures.

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 initiated 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, results of operations and cash flows.

Legal Matters

There are various lawsuits, claims (including claims for asbestos exposure) and proceedings related to the Company's normal business operations, pending against the Company, the most significant of which are described above.

12. NEW ACCOUNTING STANDARDS AND INTERPRETATIONS:

SFAS 159 – “The Fair Value Option for Financial Assets and Financial Liabilities – Including an amendment of FASB Statement No. 115”

In February 2007, FASB issued SFAS 159, which provides companies with an option to report selected financial assets and liabilities at fair value. The Standard requires companies to provide additional information that will help investors and other users of financial statements to more easily understand the effect of the company’s choice to use fair value on its earnings. The Standard also requires companies to display the fair value of those assets and liabilities for which the company has chosen to use fair value on the face of the balance sheet. This guidance does not eliminate disclosure requirements included in other accounting standards, including requirements for disclosures about fair value measurements included in SFAS 157, *Fair Value Measurements*, and SFAS 107, *Disclosures about Fair Value of Financial Instruments*. The Company is currently evaluating the impact of this Statement on its financial statements.

SFAS 157 – “Fair Value Measurements”

In September 2006, the FASB issued SFAS 157, that establishes how companies should measure fair value when they are required to use a fair value measure for recognition or disclosure purposes under GAAP. This Statement addresses the need for increased consistency and comparability in fair value measurements and for expanded disclosures about fair value measurements. The key changes to current practice are: (1) the definition of fair value which focuses on an exit price rather than entry price; (2) the methods used to measure fair value such as emphasis that fair value is a market-based measurement, not an entity-specific measurement, as well as the inclusion of an adjustment for risk, restrictions and credit standing; and (3) the expanded disclosures about fair value measurements. This Statement is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those years. The Company is currently evaluating the impact of this Statement on its financial statements.

FSP FIN 46(R)-6 – “Determining the Variability to Be Considered in Applying FASB interpretation No. 46(R)”

In April 2006, the FASB issued FSP FIN 46(R)-6 that addresses how a reporting enterprise should determine the variability to be considered in applying FASB interpretation No. 46 (revised December 2003). The Company adopted FIN 46(R) in the first quarter of 2004, consolidating VIEs when the Company or one of its subsidiaries is determined to be the VIE’s primary beneficiary. The variability that is considered in applying interpretation 46(R) affects the determination of (a) whether the entity is a VIE; (b) which interests are variable interests in the entity; and (c) which party, if any, is the primary beneficiary of the VIE. This FSP states that the variability to be considered shall be based on an analysis of the design of the entity, involving two steps:

- Step 1: Analyze the nature of the risks in the entity
- Step 2: Determine the purpose(s) for which the entity was created and determine the variability the entity is designed to create and pass along to its interest holders.

After determining the variability to consider, the reporting enterprise can determine which interests are designed to absorb that variability. The guidance in this FSP is applied prospectively to all entities (including newly created entities) with which that enterprise first becomes involved and to all entities previously required to be analyzed under interpretation 46(R) when a reconsideration event has occurred after July 1, 2006. The Company does not expect this Statement to have a material impact on its financial statements.

FIN 48 – “Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109”

In June 2006, the FASB issued FIN 48 which clarifies the accounting for uncertainty in income taxes recognized in an enterprise’s financial statements in accordance with FASB Statement No. 109, “Accounting for Income Taxes.” This interpretation prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken on a tax return. This interpretation also provides guidance on derecognition, classification, interest, penalties, accounting in interim periods, disclosure and transition. The evaluation of a tax position in accordance with this interpretation will be a two-step process. The first step will determine if it is more likely than not that a tax position will be sustained upon examination and should therefore be recognized. The second step will measure a tax position that meets the more likely than not recognition threshold to determine the amount of benefit to recognize in the financial statements. This interpretation is effective for fiscal years beginning after December 15, 2006. The Company does not expect this Statement to have a material impact on its financial statements.

13. SUMMARY OF QUARTERLY FINANCIAL DATA (UNAUDITED):

The following summarizes certain consolidated operating results by quarter for 2006 and 2005:

Three Months Ended	March 31, 2006	June 30, 2006	September 30, 2006	December 31, 2006
	<i>(In millions)</i>			
Revenues	\$ 311.2	\$ 282.2	\$ 356.2	\$ 293.5
Expenses	282.5	211.6	314.2	593.7
Operating Income (Loss)	28.7	70.6	42.0	(300.2)
Other Income (Expense)	0.5	(1.0)	(2.4)	(1.0)
Income (Loss) from Continuing Operations Before Income Taxes	29.2	69.6	39.6	(301.2)
Income Taxes	11.3	29.5	14.6	22.0
Net Income (Loss)	<u>\$ 17.9</u>	<u>\$ 40.1</u>	<u>\$ 25.0</u>	<u>\$ (323.2)</u>
	<i>(In millions)</i>			
Three Months Ended	March 31, 2005	June 30, 2005	September 30, 2005	December 31, 2005
Revenues	\$ 295.8	\$ 263.1	\$ 333.2	\$ 284.3
Expenses	268.0	238.0	330.0	265.0
Operating Income	27.8	25.1	3.2	19.3
Other Income (Expense)	(0.9)	1.4	0.7	(0.6)
Income from Continuing Operations Before Income Taxes	26.9	26.5	3.9	18.7
Income Taxes	10.4	10.8	2.9	6.0
Income Before Cumulative Effect of a Change in Accounting Principle	16.5	15.7	1.0	12.7
Cumulative Effect of a Change in Accounting Principle (Net of Income Taxes) (Note 2 (G))	-	-	-	(0.3)
Net Income	<u>\$ 16.5</u>	<u>\$ 15.7</u>	<u>\$ 1.0</u>	<u>\$ 12.4</u>