

JERSEY CENTRAL POWER & LIGHT COMPANY

2006 ANNUAL REPORT TO STOCKHOLDERS

Jersey Central Power & Light Company is a wholly owned electric utility operating subsidiary of FirstEnergy Corp. It engages in the transmission, distribution and sale of electric energy in an area of approximately 3,200 square miles in New Jersey. 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 2.6 million.

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GLOSSARY OF TERMS

The following abbreviations and acronyms are used in this report to identify Jersey Central Power and Light Company and its affiliates:

ATSI	American Transmission Systems, Inc., owns and operates transmission facilities
BGS	Basic Generation Service
CEI	The Cleveland Electric Illuminating Company, an affiliated Ohio electric utility
Companies	OE, CEI, TE, Penn, JCP&L, Met-Ed and Penelec
DRA	Division of Ratepayer Advocate
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
JCP&L Transition Funding	JCP&L Transition Funding LLC, a Delaware limited liability company and issuer of transition bonds
JCP&L Transition Funding II	JCP&L Transition Funding II LLC, a Delaware limited liability company and issuer of transition bonds
Met-Ed	Metropolitan Edison Company, an affiliated Pennsylvania electric utility
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
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
FRP	Forked River Power LLC
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
MOU	Memorandum of Understanding
MTC	Market Transition Charge
NERC	North American Electric Reliability Corporation
NJBPU	New Jersey Board of Public Utilities
NOPR	Notice of Proposed Rulemaking
NUG	Non-Utility Generation
OCI	Other Comprehensive Income
OPEB	Other Post-Employment Benefits

GLOSSARY OF TERMS, Cont'd.

PJM	PJM Interconnection LLC
PRP	Potentially Responsible Party
PUCO	Public Utilities Commission of Ohio
PUHCA	Public Utility Holding Company Act of 1935
RTOR	Regional Through and Out Rates
S&P	Standard & Poor's Ratings Service
SBC	Societal Benefits Charge
SEC	United States Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards
SFAS 71	SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation"
SFAS 87	SFAS No. 87, "Employers' Accounting for Pensions"
SFAS 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"
SRM	Special Reliability Master
TBC	Transition Bond Charge
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
Jersey Central Power & Light 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 Jersey Central Power & Light 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.

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.

JERSEY CENTRAL POWER & LIGHT 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>
GENERAL FINANCIAL INFORMATION:	(Dollars in thousands)				
Operating Revenues	<u>\$ 2,667,645</u>	<u>\$ 2,602,234</u>	<u>\$ 2,206,987</u>	<u>\$ 2,359,646</u>	<u>\$ 2,328,415</u>
Operating Income	<u>\$ 403,668</u>	<u>\$ 388,377</u>	<u>\$ 273,334</u>	<u>\$ 144,606</u>	<u>\$ 332,953</u>
Net Income	<u>\$ 190,607</u>	<u>\$ 182,927</u>	<u>\$ 107,626</u>	<u>\$ 64,277</u>	<u>\$ 248,357</u>
Earnings on Common Stock	<u>\$ 189,589</u>	<u>\$ 182,427</u>	<u>\$ 107,126</u>	<u>\$ 64,389</u>	<u>\$ 249,821</u>
Total Assets	<u>\$ 7,482,565</u>	<u>\$ 7,584,106</u>	<u>\$ 7,296,532</u>	<u>\$ 7,583,361</u>	<u>\$ 8,062,148</u>
CAPITALIZATION AS OF DECEMBER 31:					
Common Stockholder's Equity	\$ 3,159,598	\$ 3,210,763	\$ 3,143,554	\$ 3,146,180	\$ 3,270,014
Preferred Stock-					
Not Subject to Mandatory Redemption	-	12,649	12,649	12,649	12,649
Company-Obligated Mandatorily Redeemable Preferred Securities	-	-	-	-	125,244
Long-Term Debt and Other Long-Term Obligations	<u>1,320,341</u>	<u>972,061</u>	<u>1,238,984</u>	<u>1,095,991</u>	<u>1,210,446</u>
Total Capitalization	<u>\$ 4,479,939</u>	<u>\$ 4,195,473</u>	<u>\$ 4,395,187</u>	<u>\$ 4,254,820</u>	<u>\$ 4,618,353</u>
CAPITALIZATION RATIOS:					
Common Stockholder's Equity	70.5 %	76.5 %	71.5 %	73.9 %	70.8 %
Preferred Stock-					
Not Subject to Mandatory Redemption	-	0.3	0.3	0.3	0.3
Company-Obligated Mandatorily Redeemable Preferred Securities	-	-	-	-	2.7
Long-Term Debt and Other Long-Term Obligations	<u>29.5</u>	<u>23.2</u>	<u>28.2</u>	<u>25.8</u>	<u>26.2</u>
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	9,548	10,107	9,355	9,104	8,976
Commercial	9,450	9,432	8,877	8,620	8,509
Industrial	2,831	3,074	3,070	3,046	3,171
Other	<u>86</u>	<u>86</u>	<u>73</u>	<u>89</u>	<u>81</u>
Total	<u>21,915</u>	<u>22,699</u>	<u>21,375</u>	<u>20,859</u>	<u>20,737</u>
CUSTOMERS SERVED:					
Residential	958,986	950,622	941,917	931,227	921,716
Commercial	118,636	117,365	115,861	114,270	112,385
Industrial	2,592	2,640	2,666	2,705	2,759
Other	<u>1,689</u>	<u>1,601</u>	<u>1,320</u>	<u>1,345</u>	<u>1,393</u>
Total	<u>1,081,903</u>	<u>1,072,228</u>	<u>1,061,764</u>	<u>1,049,547</u>	<u>1,038,253</u>
NUMBER OF EMPLOYEES:	1,448	1,416	1,444	1,557	*

* JCP&L's employees were employed by GPU Service Company in 2002.

JERSEY CENTRAL POWER & LIGHT 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 New Jersey Board of Public Utilities, 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

Earnings on common stock increased to \$190 million in 2006 from \$182 million in 2005, as increases in operating revenues and lower other operating costs were partially offset by increases in purchased power costs. Earnings on common stock in 2005 increased to \$182 million from \$107 million in 2004, due to higher operating revenues that were partially offset by increases in purchased power and other operating costs.

Revenues

Revenues increased \$65 million or 2.5% in 2006 compared with 2005. The higher revenues reflected increases in retail generation revenues of \$150 million and miscellaneous revenue of \$6 million partially offset by declines in distribution throughput revenues of \$25 million and wholesale revenues of \$66 million. Retail generation sales revenues increased in 2006 from 2005 due to higher unit prices resulting from the BGS auction, partially offset by lower volumes. Retail generation kilowatt-hour sales declines in the residential (5.5%) and industrial (3.6%) sectors were partially offset by an increase in sales to the commercial sector (1.0%). The decline in retail generation kilowatt-hour sales was due to milder weather in 2006 compared to 2005 -- heating degree days decreased by 18.5% and cooling degree days decreased by 16.0%.

The \$25 million decline in distribution revenues was due to a 3.5% volume decrease in 2006 from the previous year, partially offset by higher composite unit prices. The higher composite prices reflected the impact of the distribution rate increase effective June 1, 2005 due to the NJBPU stipulated settlements (see Note 7). Lower residential sector deliveries and a slight change in commercial sector deliveries resulted from the milder temperatures in 2006; a decrease in industrial sector deliveries reflected slowing economic conditions in our service area.

Revenues from wholesale sales decreased by \$66 million in 2006 as compared to 2005 due to lower unit prices and a 2.0% decline in kilowatt-hour sales.

Revenues increased \$395 million or 17.9% in 2005 compared with 2004. The higher revenues consisted of increases in retail generation revenues of \$195 million, distribution throughput revenues of \$123 million and wholesale revenues of \$75 million. Retail generation sales revenues increased in 2005 from 2004 due to higher volumes and unit prices resulting from the BGS auction. Retail generation kilowatt-hour sales increases in the residential (13.9%) and commercial (13.5%) sectors more than offset a decline in sales to the industrial sector (6.3%) due to changes in customer shopping. Generation provided by alternative suppliers to residential and commercial customers as a percent of total sales in our franchise area decreased by 5.2 and 5.1 percentage points, respectively, while the percentage of shopping by industrial customers increased by 1.6 percentage points.

The \$123 million increase in distribution deliveries during 2005 was due to higher composite unit prices, coupled with a 6.2% volume increase in 2005 from the previous year. The higher composite prices reflected the impact of the distribution rate increase effective June 1, 2005 due to the NJBPU stipulated settlements (see Note 7). Higher residential and commercial sector deliveries resulted, in large part, from warmer summer temperatures and colder winter temperatures in 2005 and a slight increase in industrial sector deliveries as a result of improving economic conditions.

Changes in electric generation sales and distribution deliveries in 2006 and 2005, compared to the prior year, are summarized in the following table:

Changes in KWH Sales	2006	2005
Increase (Decrease)		
Electric Generation:		
Retail	(2.8)%	12.8%
Wholesale	(2.0)%	(5.1)%
Total Electric Generation Sales	(2.6)%	8.6%
Distribution Deliveries:		
Residential	(5.5)%	8.0%
Commercial	0.2%	6.3%
Industrial	(7.9)%	0.1%
Total Distribution Deliveries	(3.5)%	6.2%

Expenses

Total expenses increased \$50 million in 2006 and \$280 million in 2005, compared to the preceding year. The increase in 2006 was primarily due to higher purchased power costs and the absence of new regulatory asset deferrals, offset by reductions in other operating costs and amortization of regulatory assets. The increase in 2005 compared to 2004 was primarily due to higher purchased power costs. The following table presents changes in 2006 and 2005 from the prior year by expense category:

Operating Expenses - Changes	2006	2005
Increase (Decrease)		
	<i>(In millions)</i>	
Purchased power costs	\$ 91	\$ 263
Other operating costs	(54)	25
Provision for depreciation	3	5
Amortization of regulatory assets	(18)	14
Deferral of new regulatory assets	29	(29)
General taxes	(1)	2
Net increase in expenses	\$ 50	\$ 280

Purchased power increased \$91 million in 2006 compared to 2005. The increased purchased power costs have no impact on our earnings as all power is provided from the BGS auction and deferral accounting ensures the matching of revenue with purchased power expense. The increased purchased power costs reflected higher unit prices, partially offset by reduced kilowatt-hour purchases due to lower generation sales requirements as discussed above. The decrease in other operating expenses of \$54 million in 2006 reflected the absence of an accrual for a potential labor arbitration award and the impact of the labor union strike that ended in March 2005.

New regulatory asset deferrals decreased \$29 million in 2006, as the prior year reflected the NJBPU approval to defer previously incurred reliability expenses for recovery from customers. Amortization of regulatory assets decreased \$18 million in 2006 as compared to 2005 due to a reduced level of MTC revenue recovery.

Purchased power costs increased \$263 million in 2005 compared to 2004, reflecting higher kilowatt-hour purchases due to increased generation sales requirements and higher unit prices. As discussed above, the increased purchased power costs have no impact on our earnings as deferral accounting ensures the matching of revenue with purchased power expense. Other operating expenses increased \$25 million in 2005 compared to 2004, primarily due to our recording a \$16 million liability for a potential labor arbitration award.

Deferral of new regulatory assets of \$29 million in 2005 reflected the NJBPU approval to defer previously incurred reliability expenses for recovery from customers. Amortization of regulatory assets increased \$14 million in 2005 as compared to 2004 due to an increase in the level of MTC revenue recovery.

Net Interest Charges

Net interest charges increased \$2 million in 2006 and decreased \$3 million in 2005, compared to the prior year. These changes reflected debt issuances of \$382 million and redemptions of \$207 million in 2006 and redemptions of \$56 million in 2005.

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 funds from the capital markets. During 2007 and thereafter, we expect to meet our contractual obligations primarily with cash from operations, short-term credit arrangements and funds from the capital markets.

Changes in Cash Position

As of December 31, 2006, we had \$41,000 of cash and cash equivalents compared with \$102,000 as of December 31, 2005. The major sources for changes in these balances are summarized below.

Cash Flows From Operating Activities

Net cash provided from operating activities was \$190 million in 2006, \$507 million in 2005 and \$263 million in 2004, summarized as follows:

Operating Cash Flows	2006	2005	2004
		<i>(In millions)</i>	
Net income	\$ 191	\$ 183	\$ 108
Net non-cash charges	108	112	118
Pension trust contribution*	5	(54)	(37)
Cash collateral from (returned to) suppliers	(109)	135	7
Working capital and other	(5)	131	67
	\$ 190	\$ 507	\$ 263

*Pension trust contributions in 2005 and 2004 were each net of \$25 million of income tax benefits.

The \$5 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 decreased by \$317 million in 2006 from 2005 as a result of \$244 million of cash collateral returned to suppliers, \$136 million decrease from working capital and other and a \$4 million decrease in net non-cash charges, partially offset by an \$8 million increase in net income (as described under "Results of Operations") and the tax benefit in 2006 relating to the January 2007 pension contribution. The decrease in working capital and other was attributable to changes to accrued taxes of \$87 million and a decrease in cash of \$27 million from the collection of receivables.

Net cash provided from operating activities increased \$244 million in 2005 compared to 2004 due to a \$75 million increase in net income as described under "Results of Operations," a \$128 million increase in cash collateral collected from suppliers and a \$64 million increase from working capital and other, which was partially offset by a \$17 million increase in after-tax voluntary pension trust contributions in 2005 from 2004. The increase from working capital and other was attributable to a \$41 million increase in cash from the collection of receivables and a \$45 million increase in accounts payable.

Cash Flows From Financing Activities

Net cash used for financing activities was \$10 million, \$298 million and \$82 million in 2006, 2005 and 2004, respectively, primarily reflecting the new issues and redemptions shown below:

Securities Issued or Redeemed in	2006	2005	2004
	<i>(In millions)</i>		
New Issues:			
Secured notes	\$ 382	\$ -	\$ 300
Redemptions:			
FMB	\$ 40	\$ 56	\$ 290
Secured notes	150	-	-
Common stock	77	-	-
Preferred stock	13	-	-
Transition bonds	17	17	16
Other	-	-	3
Total redemptions	<u>\$ 297</u>	<u>\$ 73</u>	<u>\$ 309</u>
Short-term borrowings, net	<u>\$ 5</u>	<u>\$ (67)</u>	<u>\$ 18</u>

Net cash used for financing activities decreased \$288 million in 2006 from 2005. The decrease resulted primarily from the issuance of \$382 million in long-term debt. Net cash used for financing activities increased \$216 million in 2005 from 2004 as a result of a \$68 million increase in common stock dividends to FirstEnergy and to new financing.

We had approximately \$24 million of cash and temporary investments (which includes short-term notes receivable from associated companies) and approximately \$187 million of short-term indebtedness as of December 31, 2006. We have authorization from the FERC to incur short-term debt of up to our charter limit of \$429 million (including the utility money pool). We will not issue FMB other than as collateral for senior notes, since our senior note indentures prohibit us (subject to certain exceptions) from issuing any debt which is senior to the senior notes. As of December 31, 2006, we had the capability to issue \$678 million of additional senior notes based upon FMB collateral. As a result of our redeeming all remaining outstanding preferred stock on September 15, 2006, our applicable earnings coverage test is inoperative. In the event that we would issue preferred stock in the future, the applicable earnings coverage test will govern the amount of additional preferred stock that we may issue.

We have the ability to borrow from FirstEnergy and its regulated affiliates to meet its short-term working capital requirements. FESC administers this money pool and tracks surplus funds of FirstEnergy and its regulated subsidiaries. Companies receiving a loan under the money pool agreement 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%.

On August 24, 2006, we, FirstEnergy, OE, Penn, CEI, TE, Penelec, Met-Ed, 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. Our borrowing limit under the facility is \$425 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 sub-limit.

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 as defined under the revolving credit facility was 24%.

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

On June 8, 2006, the NJBPU approved our request to issue securitization bonds associated with BGS stranded cost deferrals. On August 10, 2006, JCP&L Transition Funding II, a wholly owned subsidiary of JCP&L, issued \$182 million of transition bonds with a weighted average interest rate of 5.5%. As required by the Electric Discount and Energy Competition Act of 1999, as amended, we used the proceeds principally to reduce stranded costs, including basic generation transition costs, through the retirement of debt, including short-term debt, or equity or both, and also to pay related expenses.

On May 12, 2006, we issued \$200 million of 6.40% secured Senior Notes due 2036. The proceeds of the offering were used to repay at maturity \$150 million aggregate principal amount of our 6.45% Senior Notes due May 15, 2006 and for general corporate purposes.

Our access to the capital markets and the costs of financing are dependent on the ratings of our securities and that of FirstEnergy. The following table shows 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>Issuer</u>	<u>Securities</u>	<u>S&P</u>	<u>Moody's</u>	<u>Fitch</u>
FirstEnergy	Senior unsecured	BBB-	Baa3	BBB
JCP&L	Senior secured	BBB+	Baa1	A-

Cash Flows From Investing Activities

Cash used for investing activities decreased \$29 million in 2006 and increased \$28 million in 2005. The decrease in 2006 resulted from a reduction of \$49 million in property additions offset by loans to associated companies and an increase in the amount of restricted funds. The increase in 2005 resulted primarily from a \$30 million increase in property additions.

Our capital spending for the period 2007-2011 is expected to be approximately \$1,336 million for property additions and improvements, of which approximately \$192 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 considered firm obligations were 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⁾	\$ 1,366	\$ 33	\$ 56	\$ 63	\$ 1,214
Short-term borrowings	187	187	-	-	-
Interest on long-term debt	1,144	81	157	151	755
Operating leases ⁽²⁾	102	8	17	15	62
Pension funding ⁽³⁾	18	18	-	-	-
Purchases ⁽⁴⁾	2,692	574	1,010	732	376
Total	\$ 5,509	\$ 901	\$ 1,240	\$ 961	\$ 2,407

⁽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 and natural gas, 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. 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 and are therefore excluded from the table below. Contracts that are not exempt from such treatment include power purchase agreements with NUG entities that were structured pursuant to the Public Utility Regulatory Act of 1978. These non-trading contracts are adjusted to fair value at the end of each quarter, with a corresponding regulatory asset recognized for above-market costs. The change in the fair value of commodity derivative contracts related to energy production during 2006 is summarized in the following table:

<u>Decrease in the Fair Value of Derivative Contracts</u>	<u>Non-Hedge</u>	<u>Hedge</u>	<u>Total</u>
	<i>(In millions)</i>		
Change in the fair value of commodity derivative contracts:			
Outstanding net liabilities as of January 1, 2006	\$ (1,223)	\$ -	\$ (1,223)
New contract value when entered	-	-	-
Additions/Changes in value of existing contracts	(239)	-	(239)
Change in techniques/assumptions	-	-	-
Settled contracts	291	-	291
Net Liabilities - Derivatives Contracts as of December 31, 2006⁽¹⁾	<u>\$ (1,171)</u>	<u>\$ -</u>	<u>\$ (1,171)</u>
Impact of Changes in Commodity Derivative Contracts⁽²⁾			
Income Statement Effects (Pre-Tax)	\$ (1)	\$ -	\$ (1)
Balance Sheet Effects:			
OCI (Pre-Tax)	\$ -	\$ -	\$ -
Regulatory Asset (Net)	\$ (53)	\$ -	\$ (53)

⁽¹⁾ Includes \$1,171 million in non-hedge commodity derivative contracts (primarily with NUGs), which are offset by a regulatory asset 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:

<u>Balance Sheet Classification</u>	<u>Non-Hedge</u>	<u>Hedge</u>	<u>Total</u>
	<i>(In millions)</i>		
Current-			
Other assets	\$ -	\$ -	\$ -
Other liabilities	-	-	-
Non-Current-			
Other deferred charges	12	-	12
Other noncurrent liabilities	(1,183)	-	(1,183)
Net liabilities	<u>\$ (1,171)</u>	<u>\$ -</u>	<u>\$ (1,171)</u>

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⁾	\$ (314)	\$ (257)	\$ (199)	\$ (191)	\$ -	\$ -	\$ (961)
Prices based on models	-	-	-	-	(111)	(99)	(210)
Total⁽²⁾	\$ (314)	\$ (257)	\$ (199)	\$ (191)	\$ (111)	\$ (99)	\$ (1,171)

⁽¹⁾ Broker quote sheets.

⁽²⁾ Includes \$1,171 million in non-hedge commodity derivative contracts (primarily with NUGs), which are offset by a regulatory asset.

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

Our exposure to fluctuations in market interest rates is reduced since our debt has fixed interest rates, as noted in the following table:

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>							
Assets								
Investments Other Than Cash and Cash Equivalents- Fixed Income						\$ 236	\$ 236	\$ 234
Average interest rate						4.8%	4.8%	
Liabilities								
Long-term Debt:								
Fixed rate	\$ 33	\$ 27	\$ 29	\$ 31	\$ 32	\$ 1,214	\$ 1,366	\$ 1,388
Average interest rate	4.7%	5.3%	5.3%	5.4%	5.6%	6.0%	6.0%	
Short-term Borrowings	\$ 187						\$ 187	\$ 187
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 \$97 million and \$84 million at December 31, 2006 and 2005, respectively. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a \$10 million reduction in fair value as of December 31, 2006 (see Note 4 Fair Value of Financial Instruments).

Outlook

Beginning in 1999, all of our customers were able to select alternative energy suppliers. We continue to deliver power to homes and businesses through our existing distribution system, which remains regulated. To support customer choice, rates were restructured into unbundled service charges and additional non-bypassable charges to recover stranded costs.

Regulatory Matters

Regulatory assets are costs which have been authorized by the NJBPU 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 of our regulatory assets are expected to continue to be recovered under the provisions of the regulatory proceedings discussed below. Our regulatory assets totaled \$2.2 billion as of December 31, 2006 and 2005.

We are permitted to defer for future collection from customers the amounts by which its costs of supplying BGS to non-shopping customers and costs incurred under NUG agreements exceed amounts collected through BGS and NUGC rates and market sales of NUG energy and capacity. As of December 31, 2006, the accumulated deferred cost balance totaled approximately \$369 million. New Jersey law allows for securitization of our deferred balance upon application and a determination by the NJBPU that the conditions of the New Jersey restructuring legislation are met. On February 14, 2003, we filed for approval to securitize the July 31, 2003 deferred balance. On June 8, 2006, the NJBPU approved our request to issue securitization bonds associated with BGS stranded cost deferrals. On August 10, 2006, JCP&L Transition Funding II, our wholly owned subsidiary, issued \$182 million of transition bonds with a weighted average interest rate of 5.5%.

On December 2, 2005, we filed a request for recovery of \$165 million of actual above-market NUG costs incurred from August 1, 2003 through October 31, 2005 and forecasted above-market NUG costs for November and December 2005. On February 23, 2006, we filed updated data reflecting actual amounts through December 31, 2005 of \$154 million of costs incurred since July 31, 2003. On July 18, 2006, we further requested an additional \$14 million of costs that had been eliminated from the securitized amount. A Stipulation of Settlement was signed by all parties, approved by the ALJ and adopted by the NJBPU in its Order dated December 6, 2006. The Order approves an annual \$110 million increase in NUGC rates designed to recover deferred costs incurred since August 1, 2003, and a portion of costs incurred prior to August 1, 2003 that were not securitized. The Order requires that we absorb any net annual operating losses associated with the Forked River Generating Station. In the Settlement, we also agreed not to seek an increase to the NUGC to become effective before January 2010, unless the deferred balance exceeds \$350 million at any time after June 30, 2007.

Reacting to the higher closing prices of the 2006 BGS fixed rate auction, the NJBPU, on March 16, 2006, initiated a generic proceeding to evaluate the auction process and potential options for the future. On April 6, 2006, initial comments were submitted. A public meeting was held on April 21, 2006 and a legislative-type hearing was held on April 28, 2006. On June 21, 2006, the NJBPU approved the continued use of a descending block auction for the Fixed Price Residential Class. JCP&L filed its 2007 BGS company specific addendum on July 10, 2006. On October 27, 2006, the NJBPU approved the auction format to procure the 2007 Commercial Industrial Energy Price as well as the specific rules for both the Fixed Price and Commercial Industrial Energy Price auctions. These rules were essentially unchanged from the prior auctions.

On August 1, 2005, the NJBPU established a proceeding to determine whether additional ratepayer protections are required at the state level in light of the repeal of PUHCA pursuant to the EPACT. The NJBPU approved regulations effective October 2, 2006 that would prevent a holding company that owns a gas or electric public utility from investing more than 25% of the combined assets of its utility and utility-related subsidiaries into businesses unrelated to the utility industry. These regulations are not expected to materially impact FirstEnergy or us. Also, in the same proceeding, the NJBPU Staff issued an additional draft proposal on March 31, 2006 addressing various issues including access to books and records, ring-fencing, cross subsidization, corporate governance and related matters. With the approval of the NJBPU Staff, the affected utilities jointly submitted an alternative proposal on June 1, 2006. Comments on the alternative proposal were submitted on June 15, 2006. On November 3, 2006, the NJBPU Staff circulated a revised draft proposal to interested stakeholders.

New Jersey statutes require that the state periodically undertake a planning process, known as the Energy Master Plan (EMP), to address energy related issues including energy security, economic growth, and environmental impact. The EMP is to be developed with involvement of the Governor's Office and the Governor's Office of Economic Growth, and is to be prepared by a Master Plan Committee, which is chaired by the NJBPU President and includes representatives of several State departments.

In October 2006 the current EMP process was initiated with the issuance of a proposed set of objectives which, as to electricity, included the following:

- Reduce the total projected electricity demand by 20% by 2020;
- Meet 22.5% of the State's electricity needs with renewable energy resources by that date;

- Reduce air pollution related to energy use;
- Encourage and maintain economic growth and development;
- Achieve a 20% reduction in both Customer Average Interruption Duration Index and System Average Interruption Frequency Index by 2020;
- Unit prices for electricity should remain no more than +5% of the regional average price (region includes New York, New Jersey, Pennsylvania, Delaware, Maryland and the District of Columbia); and
- Eliminate transmission congestion by 2020.

Comments on the objectives and participation in the development of the EMP have been solicited and a number of working groups have been formed to attain input from a broad range of interested stakeholders including utilities, environmental groups, customer groups, and major customers. Public stakeholder meetings were held in the fall of 2006 and in early 2007, and further public meetings are expected in the summer of 2007. A final draft of the EMP is expected to be presented to the Governor in the fall of 2007 with further public hearings anticipated in early 2008. At this time we cannot predict the outcome of this process nor determine its impact.

On January 17, 2007, we filed a petition with the NJBPU seeking approval of the sale of the Forked River Generating Station to Forked River Power LLC (FRP) which is indirectly owned by Maxim Power (USA), Inc., based upon terms and conditions set forth in the Purchase and Sale Agreement and other related agreements, including a Tolling Agreement with FES and a PJM Interconnection Agreement. FRP will assume all on-site environmental liabilities arising on and after the closing of the sale and we will retain pre-closing environmental liabilities. In addition to approval by the NJBPU, the sale is subject to the receipt of regulatory approvals from the FERC and the New Jersey Department of Environmental Protection.

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.

See Note 7 to the consolidated financial statements for further details and a complete discussion of regulatory matters in New Jersey.

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 unsubstantiated 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. In addition, we have accrued liabilities for environmental remediation of former manufactured gas plants in New Jersey. Those costs are being recovered by us through a non-bypassable SBC. Total liabilities of approximately \$59 million 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.

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.

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.

Pension and Other Postretirement Benefits Accounting

Our reported costs of providing non-contributory qualified and non-qualified defined pension benefits and post employment 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, FirstEnergy 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. FirstEnergy continues 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. FirstEnergy's underfunded status as of December 31, 2006 was \$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 6.0% from 5.75% and 6.0% used as of December 31, 2005 and 2004, respectively.

FirstEnergy's 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, the FirstEnergy plan assets actually earned \$567 million or 12.5%, \$325 million or 8.2% and \$415 million or 11.1%, respectively. FirstEnergy's 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 of expected return on plan assets, respectively. The 2006 expected return was based upon projections of future returns and FirstEnergy's 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 return on plan assets are deferred and amortized and will increase or decrease future net periodic pension expense, respectively.

FirstEnergy's 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 its pension plan (our share was \$18 million). In addition during 2006, FirstEnergy amended its OPEB plan effective in 2008 to cap its 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 our health care plans, and projections of future medical trend rates. The effect on JCP&L's portion of pension and OPEB costs from changes in key assumptions are as follows:

<u>Increase in Costs from Adverse Changes in Key Assumptions</u>					
<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%	\$ 1.7	\$ 0.3	\$ 2.0	
Long-term return on assets	Decrease by 0.25%	\$ 1.8	\$ 0.4	\$ 2.2	
Health care trend rate	Increase by 1%	na	\$ 0.7	\$ 0.7	

Long-Lived Assets

In accordance with SFAS No. 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 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.

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. In 2006 and 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 \$2.0 billion of goodwill.

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 our 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.

JERSEY CENTRAL POWER & LIGHT 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 (Note 2(H)):			
Electric sales	\$ 2,617,390	\$ 2,550,208	\$ 2,157,532
Excise tax collections	50,255	52,026	49,455
Total revenues	<u>2,667,645</u>	<u>2,602,234</u>	<u>2,206,987</u>
EXPENSES:			
Purchased power (Note 2(H))	1,521,329	1,429,998	1,166,430
Other operating costs (Note 2(H))	320,847	375,502	350,709
Provision for depreciation	83,172	80,013	75,163
Amortization of regulatory assets	274,704	292,668	278,559
Deferral of new regulatory assets	-	(28,862)	-
General taxes	63,925	64,538	62,792
Total expenses	<u>2,263,977</u>	<u>2,213,857</u>	<u>1,933,653</u>
OPERATING INCOME	<u>403,668</u>	<u>388,377</u>	<u>273,334</u>
OTHER INCOME (EXPENSE):			
Miscellaneous income	13,323	10,084	13,449
Interest expense	(83,411)	(81,428)	(82,567)
Capitalized interest	3,758	1,740	615
Total other expense	<u>(66,330)</u>	<u>(69,604)</u>	<u>(68,503)</u>
INCOME BEFORE INCOME TAXES	337,338	318,773	204,831
INCOME TAXES	<u>146,731</u>	<u>135,846</u>	<u>97,205</u>
NET INCOME	190,607	182,927	107,626
PREFERRED STOCK DIVIDEND REQUIREMENTS	<u>1,018</u>	<u>500</u>	<u>500</u>
EARNINGS ON COMMON STOCK	<u>\$ 189,589</u>	<u>\$ 182,427</u>	<u>\$ 107,126</u>

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

JERSEY CENTRAL POWER & LIGHT COMPANY
CONSOLIDATED BALANCE SHEETS

As of December 31,	2006	2005
	<i>(In thousands)</i>	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	\$ 41	\$ 102
Receivables-		
Customers (less accumulated provisions of \$3,524,000 and \$3,830,000, respectively, for uncollectible accounts)	254,046	258,077
Associated companies	11,574	203
Other (less accumulated provision of \$204,000 in 2005, for uncollectible accounts)	40,023	41,456
Notes receivable - associated companies	24,456	18,419
Materials and supplies, at average cost	2,043	2,104
Prepaid taxes	13,333	10,137
Other	18,076	6,928
	<u>363,592</u>	<u>337,426</u>
UTILITY PLANT:		
In service	4,029,070	3,902,684
Less - Accumulated provision for depreciation	1,473,159	1,445,718
	<u>2,555,911</u>	<u>2,456,966</u>
Construction work in progress	78,728	98,720
	<u>2,634,639</u>	<u>2,555,686</u>
OTHER PROPERTY AND INVESTMENTS:		
Nuclear fuel disposal trust	171,045	164,203
Nuclear plant decommissioning trusts	164,108	145,975
Other	2,047	2,580
	<u>337,200</u>	<u>312,758</u>
DEFERRED CHARGES AND OTHER ASSETS:		
Regulatory assets	2,152,332	2,226,591
Goodwill	1,962,361	1,985,858
Prepaid pension costs	14,660	148,054
Other	17,781	17,733
	<u>4,147,134</u>	<u>4,378,236</u>
	<u>\$ 7,482,565</u>	<u>\$ 7,584,106</u>
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	\$ 32,683	\$ 207,231
Short-term borrowings-		
Associated companies	186,540	181,346
Accounts payable-		
Associated companies	80,426	37,955
Other	160,359	149,501
Accrued taxes	1,451	54,356
Accrued interest	14,458	19,916
Cash collateral from suppliers	32,300	141,225
Other	96,150	86,884
	<u>604,367</u>	<u>878,414</u>
CAPITALIZATION (See Consolidated Statements of Capitalization):		
Common stockholder's equity	3,159,598	3,210,763
Preferred stock	-	12,649
Long-term debt and other long-term obligations	1,320,341	972,061
	<u>4,479,939</u>	<u>4,195,473</u>
NONCURRENT LIABILITIES:		
Power purchase contract loss liability	1,182,108	1,237,249
Accumulated deferred income taxes	803,944	812,034
Nuclear fuel disposal costs	183,533	175,156
Asset retirement obligations	84,446	79,527
Retirement benefits	10,207	72,454
Other	134,021	133,799
	<u>2,398,259</u>	<u>2,510,219</u>
COMMITMENTS AND CONTINGENCIES (Notes 5 and 11)		
	<u>\$ 7,482,565</u>	<u>\$ 7,584,106</u>

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

JERSEY CENTRAL POWER & LIGHT COMPANY
CONSOLIDATED STATEMENTS OF CAPITALIZATION

As of December 31,	Shares Outstanding		Dollars in Thousands	
	2006	2005	2006	2005
COMMON STOCKHOLDER'S EQUITY:				
Common stock, \$10 par value, 16,000,000 shares authorized	15,009,335	15,371,270	\$ 150,093	\$ 153,713
Other paid-in capital			2,908,279	3,003,190
Accumulated other comprehensive loss (Note 2(F))			(44,254)	(2,030)
Retained earnings (Note 8(A))			145,480	55,890
Total			3,159,598	3,210,763
PREFERRED STOCK NOT SUBJECT TO MANDATORY REDEMPTION:				
Cumulative, without par value, 15,600,000 shares authorized				
4.00% Series	-	125,000	-	12,649
LONG-TERM DEBT (Note 8(B)):				
First mortgage bonds-				
6.850% due 2006			-	40,000
7.100% due 2015			12,200	12,200
7.500% due 2023			125,000	125,000
6.750% due 2025			150,000	150,000
Total			287,200	327,200
Secured notes-				
6.450% due 2006			-	150,000
4.190% due 2006-2007			17,942	35,172
5.390% due 2007-2010			52,297	52,297
5.250% due 2007-2012			56,348	-
5.810% due 2010-2013			77,075	77,075
5.410% due 2014			25,693	-
5.520% due 2014-2018			49,220	-
5.625% due 2016			300,000	300,000
6.160% due 2013-2017			99,517	99,517
4.800% due 2018			150,000	150,000
5.610% due 2021			51,139	-
6.400% due 2036			200,000	-
Total			1,079,231	864,061
Net unamortized discount on debt			(13,407)	(11,969)
Long-term debt due within one year			(32,683)	(207,231)
Total long-term debt			1,320,341	972,061
TOTAL CAPITALIZATION			\$ 4,479,939	\$ 4,195,473

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

JERSEY CENTRAL POWER & LIGHT COMPANY
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

	Comprehensive Income	Common Stock		Other Paid-In Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings
		Number of Shares	Par Value			
<i>(Dollars in thousands)</i>						
Balance, January 1, 2004		15,371,270	\$ 153,713	\$ 3,029,894	\$ (51,765)	\$ 14,337
Net income	\$ 107,626					107,626
Net unrealized loss on investments	(5)				(5)	
Net unrealized gain on derivative instruments, net of \$1,583,000 of income taxes	1,697				1,697	
Minimum liability for unfunded retirement benefits, net of \$3,772,000 of income tax benefits	(5,461)				(5,461)	
Comprehensive income	<u>\$ 103,857</u>					
Cash dividends on preferred stock						(500)
Cash dividends on common stock						(90,000)
Purchase accounting fair value adjustment				(15,982)		
Balance, December 31, 2004		15,371,270	153,713	3,013,912	(55,534)	31,463
Net income	\$ 182,927					182,927
Net unrealized gain on derivative instruments, net of \$113,000 of income taxes	163				163	
Minimum liability for unfunded retirement benefits, net of \$36,838,000 of income taxes	53,341				53,341	
Comprehensive income	<u>\$ 236,431</u>					
Cash dividends on preferred stock						(500)
Cash dividends on common stock						(158,000)
Purchase accounting fair value adjustment				(10,722)		
Balance, December 31, 2005		15,371,270	153,713	3,003,190	(2,030)	55,890
Net income	\$ 190,607					190,607
Net unrealized gain on derivative instruments, net of \$101,000 of income taxes	147				147	
Comprehensive income	<u>\$ 190,754</u>					
Net liability for unfunded retirement benefits due to the implementation of SFAS 158, net of \$42,233,000 of income tax benefits					(42,371)	
Repurchase of common stock		(361,935)	(3,620)	(73,381)		
Preferred stock redemption premium						(663)
Restricted stock units				101		
Stock based compensation				48		
Cash dividends on preferred stock						(354)
Cash dividends on common stock						(100,000)
Purchase accounting fair value adjustment				(21,679)		
Balance, December 31, 2006		15,009,335	\$ 150,093	\$ 2,908,279	\$ (44,254)	\$ 145,480

CONSOLIDATED STATEMENTS OF PREFERRED STOCK

	Not Subject to Mandatory Redemption	
	Number of Shares	Carrying Value
<i>(Dollars in thousands)</i>		
Balance, January 1, 2004	125,000	\$ 12,649
Balance, December 31, 2004	125,000	12,649
Balance, December 31, 2005	125,000	12,649
Redemptions- 4.00% Series	(125,000)	(12,649)
Balance, December 31, 2006	-	\$ -

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

JERSEY CENTRAL POWER & LIGHT COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31,	2006	2005 <i>(In thousands)</i>	2004
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	\$ 190,607	\$ 182,927	\$ 107,626
Adjustments to reconcile net income to net cash from operating activities-			
Provision for depreciation	83,172	80,013	75,163
Amortization of regulatory assets	274,704	292,668	278,559
Deferral of new regulatory assets	-	(28,862)	-
Deferred purchased power and other costs	(281,498)	(257,418)	(263,257)
Deferred income taxes and investment tax credits, net	43,896	36,125	54,887
Accrued compensation and retirement benefits	(12,670)	(10,431)	(1,972)
NUG power contract restructuring	-	-	52,800
Cash collateral from (returned to) suppliers	(109,108)	134,563	6,662
Pension trust contribution	-	(79,120)	(62,499)
Accrued liability from arbitration decision	-	16,141	-
Decrease (increase) in operating assets-			
Receivables	1,103	28,108	(13,360)
Materials and supplies	61	331	45
Prepaid taxes	5,385	15,514	14,203
Other current assets	(2,134)	(1,090)	3,667
Increase (decrease) in operating liabilities-			
Accounts payable	53,330	42,118	(2,887)
Accrued taxes	(52,905)	34,448	3,800
Accrued interest	(5,458)	1,717	(2,564)
Other	1,272	18,970	11,780
Net cash provided from operating activities	189,757	506,722	262,653
CASH FLOWS FROM FINANCING ACTIVITIES:			
New Financing-			
Long-term debt	382,400	-	300,000
Short-term borrowings, net	5,194	-	17,547
Redemptions and Repayments-			
Long-term debt	(207,231)	(72,536)	(308,872)
Short-term borrowings, net	-	(67,187)	-
Common stock	(77,000)	-	-
Preferred stock	(13,312)	-	-
Dividend Payments-			
Common stock	(100,000)	(158,000)	(90,000)
Preferred stock	(354)	(500)	(500)
Net cash used for financing activities	(10,303)	(298,223)	(81,825)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(160,264)	(209,118)	(178,877)
Loan repayments from (loans to) associated companies, net	(6,037)	2,017	(857)
Proceeds from nuclear decommissioning trust fund sales	162,655	148,337	79,510
Investments in nuclear decommissioning trust funds	(165,550)	(151,232)	(82,405)
Other	(10,319)	1,437	1,692
Net cash used for investing activities	(179,515)	(208,559)	(180,937)
Net decrease in cash and cash equivalents	(61)	(60)	(109)
Cash and cash equivalents at beginning of year	102	162	271
Cash and cash equivalents at end of year	\$ 41	\$ 102	\$ 162
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash Paid During the Year-			
Interest (net of amounts capitalized)	\$ 80,101	\$ 78,750	\$ 83,341
Income taxes	\$ 134,279	\$ 12,385	\$ 58,549

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

JERSEY CENTRAL POWER & LIGHT COMPANY
CONSOLIDATED STATEMENTS OF TAXES

For the Years Ended December 31,	2006	2005	2004
		<i>(In thousands)</i>	
GENERAL TAXES:			
New Jersey Transitional Energy Facilities Assessment*	\$ 50,255	\$ 52,026	\$ 49,455
Social security and unemployment	8,716	7,682	8,287
Real and personal property	4,762	4,567	4,894
Other	192	263	156
Total general taxes	\$ 63,925	\$ 64,538	\$ 62,792
PROVISION FOR INCOME TAXES:			
Currently payable-			
Federal	\$ 78,447	\$ 77,783	\$ 27,701
State	24,388	21,899	14,617
	102,835	99,682	42,318
Deferred, net-			
Federal	33,870	27,335	50,817
State	10,918	10,167	5,657
	44,788	37,502	56,474
Investment tax credit amortization	(892)	(1,338)	(1,587)
Total provision for income taxes	\$ 146,731	\$ 135,846	\$ 97,205
RECONCILIATION OF FEDERAL INCOME TAX EXPENSE AT STATUTORY RATE TO TOTAL PROVISION FOR INCOME TAXES:			
Book income before provision for income taxes	\$ 337,338	\$ 318,773	\$ 204,831
Federal income tax expense at statutory rate	\$ 118,068	\$ 111,571	\$ 71,691
Increases (reductions) in taxes resulting from-			
Amortization of investment tax credits	(892)	(1,338)	(1,587)
State income taxes, net of federal income tax benefit	22,948	20,843	13,178
Other, net	6,607	4,770	13,923
Total provision for income taxes	\$ 146,731	\$ 135,846	\$ 97,205
ACCUMULATED DEFERRED INCOME TAXES AS OF DECEMBER 31:			
Property basis differences	\$ 436,122	\$ 416,005	\$ 361,640
Deferred sale and leaseback costs	(19,825)	(18,942)	(17,836)
Purchase accounting basis difference	(1,253)	(1,253)	(1,253)
Sale of generation assets	236	(17,861)	(17,861)
Regulatory transition charge	253,626	227,379	213,665
Customer receivables for future income taxes	3,655	6,589	(27,239)
Oyster Creek securitization	161,862	173,177	184,245
Other comprehensive income	(43,645)	(1,402)	(38,353)
Nuclear decommissioning	(16,204)	(9,881)	(11,178)
Employee benefits	35,818	29,182	1,652
Other	(6,448)	9,041	(1,741)
Net deferred income tax liability	\$ 803,944	\$ 812,034	\$ 645,741

* 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 JCP&L (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, Met-Ed and Penelec.

The Company follows GAAP and complies with the regulations, orders, policies and practices prescribed by the SEC, NJBPU 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 and VIEs for which the Company or any of its subsidiaries is the primary beneficiary. 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.

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 NJBPU 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. As of December 31, 2006, regulatory assets that do not earn a return totaled approximately \$128 million, consisting of outage funding costs (\$32 million), post employment benefit costs (\$20 million) and reliability costs (\$14 million).

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

	<u>2006</u>	<u>2005</u>
	<i>(In millions)</i>	
Non-utility generation	\$ 1,399	\$ 1,713
Regulatory transition costs	739	464
Basic generation service	69	52
Societal benefits charge	11	29
Property losses and unrecovered plant costs	19	29
Customer receivables for future income taxes	22	31
Employee postretirement benefit costs	20	23
Loss on reacquired debt	11	10
Reliability costs	14	23
Component removal costs	(148)	(148)
Other	(4)	1
Total	<u>\$ 2,152</u>	<u>\$ 2,227</u>

Regulatory transition charges as of December 31, 2006 for the Company are approximately \$2.2 billion. Deferral of above-market costs from power supplied by NUGs to the Company are approximately \$1.4 billion and are being recovered through BGS and MTC revenues. The liability for projected above-market NUG costs and corresponding regulatory asset are adjusted to fair value at the end of each quarter. Recovery of the remaining regulatory transition costs is expected to continue under the provisions of the various regulatory proceedings in New Jersey.

(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 New Jersey. 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 \$254 million (billed – \$128 million and unbilled – \$126 million) and \$258 million (billed – \$157 million and unbilled – \$101 million) as of December 31, 2006 and 2005, respectively.

(D) PROPERTY, PLANT AND EQUIPMENT-

The majority of the Company's property, plant and equipment is reflected at original cost since such assets remain subject to rate regulation on a historical cost basis. In addition to its wholly owned facilities, the Company holds a 50% ownership interest in Yards Creek Pumped Storage Facility, and its net book value was approximately \$20 million as of December 31, 2006. 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 2.1% in 2006, 2.2% in 2005 and 2.1% in 2004.

(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.

Investments-

At the end of each reporting period, the Company evaluates its investments for impairment. In accordance with SFAS 115 and FSP SFAS 115-1 and SFAS 124-1, investments classified as available-for-sale securities 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 investment 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(B) and (C).

Goodwill

In a business combination, the excess of the purchase price over the estimated fair values of assets acquired and liabilities assumed is recognized as goodwill. Based on the guidance provided by SFAS 142, 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 is 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 2006 annual review was completed in the third quarter of 2006 with no impairment 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. As of December 31, 2006, the Company had recorded goodwill of approximately \$2.0 billion related to the merger. In 2006 and 2005, the Company adjusted goodwill to reverse pre-merger tax accruals related to the GPU acquisition.

(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 and preferred stockholders. 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 \$42 million and unrealized losses on derivative instrument hedges of \$2 million. As of December 31, 2005, AOCL consisted of unrealized losses on derivative instrument hedges of \$2 million.

(G) 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 carry forward 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.

(H) 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. Through the BGS auction process, FES was a supplier of power to the Company through May 31, 2006. The primary affiliated companies transactions are as follows:

	<u>2006</u>	<u>2005</u>	<u>2004</u>
		<i>(In millions)</i>	
Revenues:			
Wholesale sales – affiliated companies	\$ 14	\$ 33	\$ 49
Expenses:			
Service Company support services	93	94	95
Power purchased from FES	25	78	71

FirstEnergy does not bill directly or allocate any of its costs to any subsidiary company. Costs are allocated to the Company from FESC, 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 total for direct payroll, number of employees, asset balances, revenues, number of customers, other factors and specific departmental charge ratios. It is management's belief that allocation methods utilized are reasonable. Intercompany transactions with FirstEnergy and its other subsidiaries are generally settled under commercial terms within thirty days.

3. PENSION AND OTHER POSTRETIREMENT BENEFITS

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 \$18 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. JCP&L's incremental impact of adopting SFAS 158 was a decrease of \$153 million in pension assets, a decrease of \$69 million in pension liabilities and a decrease in AOCL of \$42 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>\$ 15</u>	<u>\$ 148</u>	<u>\$ (8)</u>	<u>\$ (70)</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>\$ (5)</u>	<u>\$ (1)</u>	<u>\$ 7</u>	<u>\$ 2</u>	<u>\$ 7</u>	<u>\$ 5</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	\$ 1,366	\$ 1,388	\$ 1,191	\$ 1,214

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) INVESTMENTS-

Investments other than cash and cash equivalents are available-for-sale securities primarily held in the spent nuclear fuel trust. The Company periodically evaluates its investments for other-than-temporary impairment. They first consider their intent and ability to hold the investment until recovery and then consider, 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. The following table provides the approximate fair value and related carrying amounts of investments except investments of \$2 million excluded by SFAS 107, "Disclosures about Fair Values of Financial Instruments", 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>			
Debt securities:				
–Government obligations ⁽¹⁾	169	165	166	162

⁽¹⁾ Excludes \$2 million of cash in 2006

The spent nuclear fuel disposal investments consist of debt securities classified as available-for-sale with the fair value determined based on quoted market prices. The average maturity of the securities as of December 31 is 7 years for 2006 and 6 years for 2005.

The following table provides the amortized cost basis, unrealized gains and losses, and fair values for the above investments:

	2006				2005			
	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
	<i>(In millions)</i>							
Debt securities	\$ 169	-	4	165	166	-	4	162

Proceeds from the sale of investments, 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	\$ 61	\$ 59	\$ 204
Realized gains	-	-	4
Realized losses	2	-	-
Interest and dividend income	8	9	8

(C) NUCLEAR DECOMMISSIONING TRUST FUND INVESTMENTS-

Nuclear decommissioning trust investments are classified as available-for-sale. The Company has no securities held for trading purposes. The following table provides the approximate carrying value, which equals fair value of the nuclear decommissioning trusts as of December 31, 2006 and 2005, respectively. The fair value was determined using the specific identification method of investments other than cash and cash equivalents as of December 31.

	2006	2005
	<i>(In millions)</i>	
Debt securities		
-Government obligations	\$ 53	\$ 51
-Corporate debt securities	14	11
	<u>67</u>	<u>62</u>
Equity securities	97	84
	<u>\$ 164</u>	<u>\$ 146</u>

The following table summarizes the amortized cost basis, gross unrealized gains and losses and fair values for 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	\$ 65	\$ 2	\$ -	\$ 67	\$ 60	\$ 2	\$ -	\$ 62
Equity securities	73	24	-	97	73	12	1	84
	<u>\$ 138</u>	<u>\$ 26</u>	<u>\$ -</u>	<u>\$ 164</u>	<u>\$ 133</u>	<u>\$ 14</u>	<u>\$ 1</u>	<u>\$ 146</u>

Proceeds from the sale of 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:

	<u>2006</u>	<u>2005</u>	<u>2004</u>
		<i>(In millions)</i>	
Proceeds from sales	\$ 164	\$ 121	\$ 119
Gross realized gains	1	4	15
Gross realized losses	3	5	1
Interest and dividend income	5	4	4

The Company's 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 decommissioning liabilities are 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:

	<u>2006</u>	<u>2005</u>	<u>2004</u>
		<i>(In millions)</i>	
Operating leases:			
Interest element	\$ 2.8	\$ 2.6	\$ 2.6
Other	4.5	3.2	3.7
Total rentals	<u>\$ 7.3</u>	<u>\$ 5.8</u>	<u>\$ 6.3</u>

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

	<u>Operating Leases</u>
	<i>(In millions)</i>
2007	\$ 8.3
2008	8.5
2009	8.5
2010	8.0
2011	7.0
Years thereafter	62.1
Total minimum lease payments	<u>\$ 102.4</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 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 five 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 variable interests in the remaining five entities, which sell their output at variable prices that correlate to some extent with the operating costs of the plants.

As required by FIN 46R, the Company periodically requests the information necessary from these entities to determine whether they are VIEs or whether the Company is the primary beneficiary. The Company has been unable to obtain the requested information, which in most cases, 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 net above-market loss liability recognized was \$221 million. The purchased power costs from these entities during 2006, 2005, and 2004 were \$81 million, \$101 million, and \$94 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.

As a result of outages experienced in the Company's service area in 2002 and 2003, the NJBPU had implemented reviews into the Company's service reliability. In 2004, the NJBPU adopted an MOU that set out specific tasks related to service reliability to be performed by the Company and a timetable for completion and endorsed the Company's ongoing actions to implement the MOU. On June 9, 2004, the NJBPU approved a Stipulation that incorporates the final report of an SRM who made recommendations on appropriate courses of action necessary to ensure system-wide reliability. The Stipulation also incorporates the Executive Summary and Recommendation portions of the final report of a focused audit of the Company's Planning and Operations and Maintenance programs and practices (Focused Audit). On February 11, 2005, the Company met with the DRA to discuss reliability improvements. The SRM completed his work and issued his final report to the NJBPU on June 1, 2006. The Company filed a comprehensive response to the NJBPU on July 14, 2006. The Company continues to file compliance reports reflecting activities associated with the MOU and Stipulation.

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.

The Company is permitted to defer for future collection from customers the amounts by which its costs of supplying BGS to non-shopping customers and costs incurred under NUG agreements exceed amounts collected through BGS and NUGC rates and market sales of NUG energy and capacity. As of December 31, 2006, the accumulated deferred cost balance totaled approximately \$369 million. New Jersey law allows for securitization of the Company's deferred balance upon application by the Company and a determination by the NJBPU that the conditions of the New Jersey restructuring legislation are met. On February 14, 2003, the Company filed for approval to securitize the July 31, 2003 deferred balance. On June 8, 2006, the NJBPU approved the Company's request to issue securitization bonds associated with BGS stranded cost deferrals. On August 10, 2006, JCP&L Transition Funding II, a wholly owned subsidiary of the Company, issued \$182 million of transition bonds with a weighted average interest rate of 5.5%.

On December 2, 2005, the Company filed its request for recovery of \$165 million of actual above-market NUG costs incurred from August 1, 2003 through October 31, 2005 and forecasted above-market NUG costs for November and December 2005. On February 23, 2006, the Company filed updated data reflecting actual amounts through December 31, 2005 of \$154 million of costs incurred since July 31, 2003. On July 18, 2006, the Company further requested an additional \$14 million of costs that had been eliminated from the securitized amount. A Stipulation of Settlement was signed by all parties, approved by the ALJ and adopted by the NJBPU in its Order dated December 6, 2006. The Order approves an annual \$110 million increase in NUGC rates designed to recover deferred costs incurred since August 1, 2003, and a portion of costs incurred prior to August 1, 2003 that were not securitized. The Order requires that the Company absorb any net annual operating losses associated with the Forked River Generating Station. In the Settlement, the Company also agreed not to seek an increase to the NUGC to become effective before January 2010, unless the deferred balance exceeds \$350 million at any time after June 30, 2007.

Reacting to the higher closing prices of the 2006 BGS fixed rate auction, the NJBPU, on March 16, 2006, initiated a generic proceeding to evaluate the auction process and potential options for the future. On April 6, 2006, initial comments were submitted. A public meeting was held on April 21, 2006 and a legislative-type hearing was held on April 28, 2006. On June 21, 2006, the NJBPU approved the continued use of a descending block auction for the Fixed Price Residential Class. The Company filed its 2007 BGS company specific addendum on July 10, 2006. On October 27, 2006, the NJBPU approved the auction format to procure the 2007 Commercial Industrial Energy Price as well as the specific rules for both the Fixed Price and Commercial Industrial Energy Price auctions. These rules were essentially unchanged from the prior auctions.

In accordance with an April 28, 2004 NJBPU order, the Company filed testimony on June 7, 2004 supporting a continuation of the current level and duration of the funding of TMI-2 decommissioning costs by New Jersey customers without a reduction, termination or capping of the funding. On September 30, 2004, the Company filed an updated TMI-2 decommissioning study. This study resulted in an updated total decommissioning cost estimate of \$729 million (in 2003 dollars) compared to the estimated \$528 million (in 2003 dollars) from the prior 1995 decommissioning study. The DRA filed comments on February 28, 2005 requesting that decommissioning funding be suspended. On March 18, 2005, the Company filed a response to the Ratepayer Advocate's comments. A schedule for further NJBPU proceedings has not yet been set.

On August 1, 2005, the NJBPU established a proceeding to determine whether additional ratepayer protections are required at the state level in light of the repeal of PUHCA pursuant to the EPACK. The NJBPU approved regulations effective October 2, 2006 that would prevent a holding company that owns a gas or electric public utility from investing more than 25% of the combined assets of its utility and utility-related subsidiaries into businesses unrelated to the utility industry. These regulations are not expected to materially impact FirstEnergy or the Company. Also, in the same proceeding, the NJBPU Staff issued an additional draft proposal on March 31, 2006 addressing various issues including access to books and records, ring-fencing, cross subsidization, corporate governance and related matters. With the approval of the NJBPU Staff, the affected utilities jointly submitted an alternative proposal on June 1, 2006. Comments on the alternative proposal were submitted on June 15, 2006. On November 3, 2006, the NJBPU Staff circulated a revised draft proposal to interested stakeholders.

New Jersey statutes require that the state periodically undertake a planning process, known as the Energy Master Plan (EMP), to address energy related issues including energy security, economic growth, and environmental impact. The EMP is to be developed with involvement of the Governor's Office and the Governor's Office of Economic Growth, and is to be prepared by a Master Plan Committee, which is chaired by the NJBPU President and includes representatives of several State departments.

In October 2006 the current EMP process was initiated with the issuance of a proposed set of objectives which, as to electricity, included the following:

- Reduce the total projected electricity demand by 20% by 2020;
- Meet 22.5% of the State's electricity needs with renewable energy resources by that date;
- Reduce air pollution related to energy use;
- Encourage and maintain economic growth and development;
- Achieve a 20% reduction in both Customer Average Interruption Duration Index and System Average Interruption Frequency Index by 2020;
- Unit prices for electricity should remain no more than +5% of the regional average price (region includes New York, New Jersey, Pennsylvania, Delaware, Maryland and the District of Columbia); and
- Eliminate transmission congestion by 2020.

Comments on the objectives and participation in the development of the EMP have been solicited and a number of working groups have been formed to attain input from a broad range of interested stakeholders including utilities, environmental groups, customer groups, and major customers. Public stakeholder meetings were held in the fall of 2006 and in early 2007, and further public meetings are expected in the summer of 2007. A final draft of the EMP is expected to be presented to the Governor in the fall of 2007 with further public hearings anticipated in early 2008. At this time the Company cannot predict the outcome of this process nor determine its impact.

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, the Company, Met-Ed, 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. The Company, Met-Ed 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. The Company, Met-Ed 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 January 17, 2007, the Company filed a petition with the NJBPU seeking approval of the sale of the Forked River Generating Station to Forked River Power LLC (FRP) which is indirectly owned by Maxim Power (USA), Inc., based upon terms and conditions set forth in the Purchase and Sale Agreement and other related agreements, including a Tolling Agreement with FES and a PJM Interconnection Agreement. FRP will assume all on-site environmental liabilities arising on and after the closing of the sale and the Company will retain pre-closing environmental liabilities. In addition to approval by the NJBPU, the sale is subject to the receipt of regulatory approvals from the FERC and the New Jersey Department of Environmental Protection.

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) RETAINED EARNINGS-

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. As of December 31, 2006, the Company had retained earnings available to pay common stock dividends of \$144 million, net of amounts restricted under the Company's first mortgage indenture.

(B) LONG-TERM DEBT-

Securitized Transition Bonds

The consolidated financial statements of JCP&L include the results of JCP&L Transition Funding and JCP&L Transition Funding II, wholly owned limited liability companies of JCP&L. In June 2002, JCP&L Transition Funding sold \$320 million of transition bonds to securitize the recovery of JCP&L's bondable stranded costs associated with the previously divested Oyster Creek Nuclear Generating Station. In August 2006, JCP&L Transition Funding II sold \$182 million of transition bonds to securitize the recovery of deferred costs associated with JCP&L's supply of BGS.

JCP&L did not purchase and does not own any of the transition bonds, which are included as long-term debt on FirstEnergy's Consolidated Balance Sheet. As of December 31, 2006, \$429 million of transition bonds are outstanding. The transition bonds are the sole obligations of JCP&L Transition Funding and JCP&L Transition Funding II and are collateralized by each company's equity and assets, which consists primarily of bondable transition property.

Bondable transition property represents the irrevocable right under New Jersey law of a utility company to charge, collect and receive from its customers, through a non-bypassable TBC, the principal amount and interest on transition bonds and other fees and expenses associated with their issuance. JCP&L sold its bondable transition property to JCP&L Transition Funding and JCP&L Transition Funding II and, as servicer, manages and administers the bondable transition property, including the billing, collection and remittance of the TBC, pursuant to separate servicing agreements with JCP&L Transition Funding and JCP&L Transition Funding II. For the two series of transition bonds, JCP&L is entitled to aggregate annual servicing fees of up to \$628,000 that are payable from TBC collections.

Other 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 \$10 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:

	<u>(In millions)</u>	
2007	\$	33
2008		27
2009		29
2010		31
2011		32

9. ASSET RETIREMENT OBLIGATION:

JCP&L 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 \$84 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 \$164 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 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.

<u>ARO Reconciliation</u>	<u>2006</u>	<u>2005</u>
	<u>(In millions)</u>	
Balance at beginning of year	\$ 80	\$ 73
Accretion	4	5
FIN 47 ARO upon adoption	-	2
Balance at end of year	<u>\$ 84</u>	<u>\$ 80</u>

10. SHORT-TERM BORROWINGS:

Short-term borrowings outstanding as of December 31, 2006 consisted of \$187 million of borrowings from affiliates. On August 24, 2006, the Company, FirstEnergy, OE, Penn, CEI, TE, Penelec, Met-Ed, 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 \$425 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 \$0.2 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 it has an obligation for such costs and can reasonably estimate the amount of such costs. Unasserted claims are reflected in the Company's 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. In addition, the Company has accrued liabilities for environmental remediation of former manufactured gas plants in New Jersey. Those costs are being recovered by the Company through a non-bypassable SBC. Total liabilities of approximately \$59 million have been accrued through December 31, 2006.

(C) OTHER LEGAL PROCEEDINGS-

Power Outages and Related Litigation

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

In August 2002, the trial court granted partial summary judgment to the Company and dismissed the plaintiffs' claims for consumer fraud, common law fraud, negligent misrepresentation, and strict product liability. In November 2003, the trial court granted the Company's motion to decertify the class and denied plaintiffs' motion to permit into evidence their class-wide damage model indicating damages in excess of \$50 million. These class decertification and damage rulings were appealed to the Appellate Division. The Appellate Division issued a decision on July 8, 2004, affirming the decertification of the originally certified class, but remanding for certification of a class limited to those customers directly impacted by the outages of JCP&L transformers in Red Bank, New Jersey. In 2005, the Company renewed its motion to decertify the class based on a very limited number of class members who incurred damages and also filed a motion for summary judgment on the remaining plaintiffs' claims for negligence, breach of contract and punitive damages. In July 2006, the New Jersey Superior Court dismissed the punitive damage claim and again decertified the class based on the fact that a vast majority of the class members did not suffer damages and those that did would be more appropriately addressed in individual actions. Because it effectively terminates this class action, plaintiffs appealed this ruling to the New Jersey Appellate Division, where the matter is currently pending. FirstEnergy is unable to predict the outcome of these matters and no liability has been accrued as of December 31, 2006.

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 was also named, along with several other entities, in a complaint in New Jersey State Court. The allegations against FirstEnergy were based, in part, on an alleged failure to protect the citizens of Jersey City from an electrical power outage. None of FirstEnergy's subsidiaries serve customers in Jersey City. A responsive pleading has been filed. On April 28, 2006, the Court granted FirstEnergy's motion to dismiss. The plaintiff has not appealed.

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. Although unable to predict the impact of these proceedings, 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.

Other Legal Matters

The Company's bargaining unit employees filed a grievance challenging the Company's 2002 call-out procedure that required bargaining unit employees to respond to emergency power outages. On May 20, 2004, an arbitration panel concluded that the call-out procedure violated the parties' collective bargaining agreement. At the conclusion of the June 1, 2005 hearing, the arbitration panel decided not to hear testimony on damages and closed the proceedings. On September 9, 2005, the arbitration panel issued an opinion to award approximately \$16 million to the bargaining unit employees. On February 6, 2006, a federal district court granted a union motion to dismiss, as premature, a Company appeal of the award filed on October 18, 2005. The Company intends to re-file an appeal again in federal district court once the damages associated with this case are identified at an individual employee level. The Company recognized a liability for the potential \$16 million award in 2005.

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

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). 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. 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):

<u>Three Months Ended</u>	<u>March 31, 2006</u>	<u>June 30, 2006</u>	<u>September 30, 2006</u>	<u>December 31, 2006</u>
	<i>(In millions)</i>			
Revenues	\$ 575.8	\$ 611.5	\$ 911.1	\$ 569.3
Expenses	502.3	515.8	755.1	490.9
Operating Income	73.5	95.7	156.0	78.4
Other Expense	(16.2)	(16.8)	(18.3)	(15.0)
Income Before Income Taxes	57.3	78.9	137.7	63.4
Income Taxes	23.6	38.6	58.3	26.2
Net Income	<u>\$ 33.7</u>	<u>\$ 40.3</u>	<u>\$ 79.4</u>	<u>\$ 37.2</u>
Earnings on Common Stock	<u>\$ 33.6</u>	<u>\$ 40.2</u>	<u>\$ 78.5</u>	<u>\$ 37.3</u>

<u>Three Months Ended</u>	<u>March 31, 2005</u>	<u>June 30, 2005</u>	<u>September 30, 2005</u>	<u>December 31, 2005</u>
	<i>(In millions)</i>			
Revenues	\$ 529.1	\$ 595.3	\$ 900.3	\$ 577.6
Expenses	482.2	478.8	753.5	499.4
Operating Income	46.9	116.5	146.8	78.2
Other Expense	(20.2)	(19.5)	(14.7)	(15.2)
Income Before Income Taxes	26.7	97.0	132.1	63.0
Income Taxes	13.2	42.7	58.1	21.8
Net Income	<u>\$ 13.5</u>	<u>\$ 54.3</u>	<u>\$ 74.0</u>	<u>\$ 41.2</u>
Earnings on Common Stock	<u>\$ 13.3</u>	<u>\$ 54.2</u>	<u>\$ 73.7</u>	<u>\$ 41.2</u>