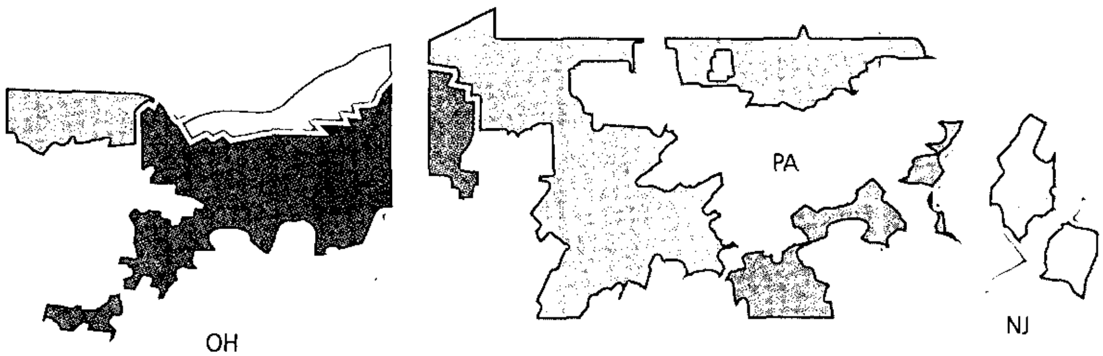
FirstEnergy

SUMMARY

2007 ANNUAL REPORT

ELECTRIC UTILITY OPERATING COMPANIES



- The Toledo Edison Company
- The Cleveland Electric Illuminating Company
- Ohio Edison Company
- Pennsylvania Power Company
- Pennsylvania Electric Company
- Metropolitan Edison Company
- Jersey Central Power & Light Company

This Summary Annual Report includes financial and operating highlights and summary financial statements. For complete financial statements, including notes, please refer to FirstEnergy's 2007 Form 10-K filing, which is available online at the Company's Web site (www.firstenergycorp.com/ir).

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CORPORATE PROFILE

FirstEnergy is a diversified energy company headquartered in Akron, Ohio. Its subsidiaries and affiliates are involved in the generation, transmission and distribution of electricity, as well as energy management and other energy-related services. Its seven electric utility operating companies comprise the nation's fifth largest investor-owned electric system, based on 4.5 million customers served within a 36,100-square-mile area of Ohio, Pennsylvania and New Jersey. Its generation subsidiaries control more than 14,000 megawatts of capacity.

FINANCIAL HIGHLIGHTS

(Dollars in millions, except per share amounts)

	2007	2006
Total revenues	**$12,802**	$11,501
Income from continuing operations*	**$ 1,309**	$ 1,258
Net income	**$ 1,309**	$ 1,254
Basic earnings per common share:		
Income from continuing operations	**$ 4.27**	$ 3.85
Net earnings per basic share	**$ 4.27**	$ 3.84
Diluted earnings per common share:		
Income from continuing operations	**$ 4.22**	$ 3.82
Net earnings per diluted share	**$ 4.22**	$ 3.81
Dividends paid per common share**	**$ 2.00**	$ 1.80
Book value per common share	**$ 29.45**	$ 28.35
Net cash from operating activities	**$ 1,694**	$ 1,939

* *The 2006 discontinued operations are described in Note 8 to the consolidated financial statements, which can be found in FirstEnergy's 2007 Annual Report on Form 10-K.*

** *A quarterly dividend of $0.55 was paid on March 1, 2008, increasing the indicated annual dividend rate to $2.20 per share.*

Forward-Looking Statements: This Summary Annual Report includes forward-looking statements based on information currently available to management. Such statements are subject to certain risks and uncertainties. These statements include declarations regarding our, or our management's, intents, beliefs and current expectations. These statements typically contain, but are not limited to, the terms "anticipate," "potential," "expect," "believe," "estimate" and similar words. Forward-looking statements involve estimates, assumptions, known and unknown risks, uncertainties and other factors that may cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Actual results may differ materially due to the speed and nature of increased competition in the electric utility industry and legislative and regulatory changes affecting how generation rates will be determined following the expiration of existing rate plans in Ohio and Pennsylvania, 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 of FirstEnergy's regulated utilities to collect transition and other charges or to recover increased transmission costs, maintenance costs being higher than anticipated, other legislative and regulatory changes including revised environmental requirements and possible greenhouse gas emissions regulation, the uncertainty of the timing and amounts of the capital expenditures needed to, among other things, implement the Air Quality Compliance Plan (including that such amounts could be higher than anticipated) or levels of emission reductions related to the Consent Decree resolving the New Source Review litigation or other potential regulatory initiatives, adverse regulatory or legal decisions and outcomes (including, but not limited to, the revocation of necessary licenses or operating permits and oversight by the Nuclear Regulatory Commission including, but not limited to, the Demand for Information issued to FENOC on May 14, 2007) as disclosed in our SEC filings, the timing and outcome of various proceedings before the PUCO (including, but not limited to, the Distribution Rate Cases and the generation supply plan filing for the Ohio Companies and the successful resolution of the issues remanded to the PUCO by the Supreme Court of Ohio regarding the Rate Stabilization Plan and the Rate Certainty Plan, including the deferral of fuel costs) and the PPUC (including the resolution of the Petitions for Review filed with the Commonwealth Court of Pennsylvania with respect to the transition rate plan for Met-Ed and Penelec), the continuing availability of generating units and their ability to continue to operate at or near full capacity, the ability to comply with applicable state and federal reliability standards, the ability to accomplish or realize anticipated benefits from strategic goals (including employee workforce initiatives), the ability to improve electric commodity margins and to experience growth in the distribution business, changing market conditions that could affect the value of assets held in our nuclear decommissioning trust fund, pension fund and other trust funds, the ability to access the public securities and other capital markets and the cost of such capital, the risks and other factors discussed from time to time in our SEC filings, and other similar factors. The foregoing review of factors should not be construed as exhaustive. New factors emerge from time to time, and it is not possible for us to predict all such factors, nor can we assess the impact of any such factor on our business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements. We expressly disclaim any current intention to update any forward-looking statements contained herein as a result of new information, future events, or otherwise.

MESSAGE TO SHAREHOLDERS

In 2007, we achieved the strongest results in our 10-year history – and, by many key measures, we've become one of our industry's top performers.

Through our focus on continuous improvement, we increased the productivity and efficiency of our power plants, enhanced the reliability of our service, and provided greater value to shareholders.

Our key accomplishments for the year included:

- *Posting the best safety record in our Company's history and one of the best in our industry – an Occupational Health and Safety Administration (OSHA) recordable rate of 0.86 incidents per 100 employees*
- *Delivering a total shareholder return of 23.6 percent – among the best in our industry*
- *Achieving record earnings of $4.27 per share while generating approximately $1.7 billion in cash from operations*
- *Raising the annual dividend rate for the fifth time in three years, for a total increase of 47 percent*
- *Producing 81 million megawatt-hours (MWH) from our generating plants, nearly matching our record 2006 performance*

Our record earnings per share – up 11 percent compared to 2006 – were near the top of our guidance to the financial community. These strong results were driven by increased electric generation sales, which more than offset higher purchased power costs.

We also enhanced shareholder value through our accelerated share repurchase program, which reduced outstanding shares by 25 million, or nearly 8 percent, since 2005. And, in December, your Board of Directors approved a 10-percent increase in the dividend, bringing the annual rate to $2.20 per share of common stock, up from $1.50 in 2004.

Anthony J. Alexander, President and Chief Executive Officer

These and other accomplishments over the past three years have produced an annualized total shareholder return of 26.4 percent and an increase in the market value of our Company for shareholders of $9 billion – among the best financial performances in the electric utility industry over that period.

Our three-year financial performance and strong prospects for growth helped us earn recognition from *Public Utilities Fortnightly* magazine as one of the nation's 40 Best Energy Companies.

Working Safely

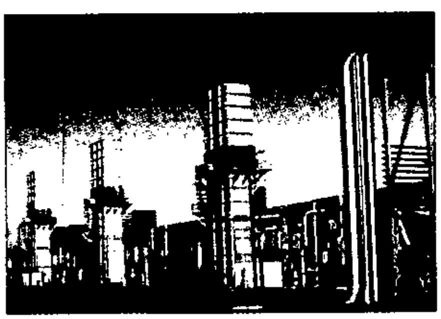
Our employees achieved the best safety results in our history and one of the best in the industry. Our OSHA recordable rate of 0.86 represents less than one recordable incident per 200,000 hours worked. Employees at 12 Company locations had no OSHA recordable incidents in 2007, and our Davis-Besse and Perry nuclear plant employees have worked a combined 12.4 million hours without a lost-time accident.

Despite these strong results, we were tragically reminded earlier this month that a life can be lost in an instant when working with electricity. That's why we stress with employees that safety must be their first priority during every minute while on the job.

Moving Toward Competitive Markets

As our progress indicates, we continue to execute our strategies for future growth – strategies that recognize the many opportunities competitive markets offer.

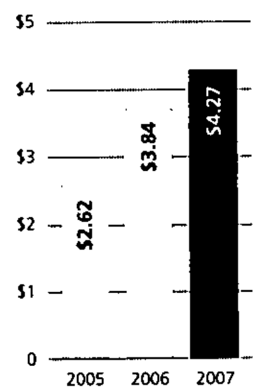
With this in mind, we remain active in the debate concerning Senate Bill 221, proposed legislation that would restructure Ohio's electric industry. We are actively supporting specific language in the legislation that would maintain a market option for meeting our customers' generating needs or a rate plan option that would continue to manage the transition to fully competitive markets. We remain hopeful that the final bill will strike the right balance for ensuring that competitive markets continue to benefit our customers and Company.



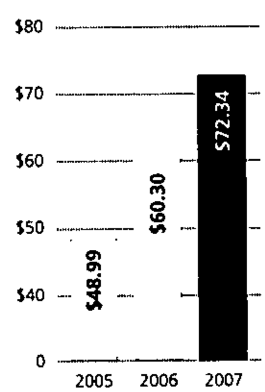
West Lorain natural gas plant

Our Pennsylvania Power utility made a successful transition in 2007 to a fully competitive market that provides customer choice for generation. A bidding process is being used to establish generation prices for customers through 2011.

BASIC EARNINGS PER SHARE



YEAR-END STOCK PRICE



Maximizing Our Generation Business

We believe our competitive generation business offers the best prospects for our future growth. Toward that end, we're pursuing a strategy to maximize the productivity of our power plants and wholesale marketing activities while taking advantage of cost-effective opportunities to add capacity.

The strong performance of our generating assets – now part of our FirstEnergy Solutions (FES) subsidiary – was led by our nuclear operations, which produced a record 30.3 million MWH of our total generation. FES has become one of the nation's largest competitive electricity suppliers, with more than 100 million MWH of power sales annually.

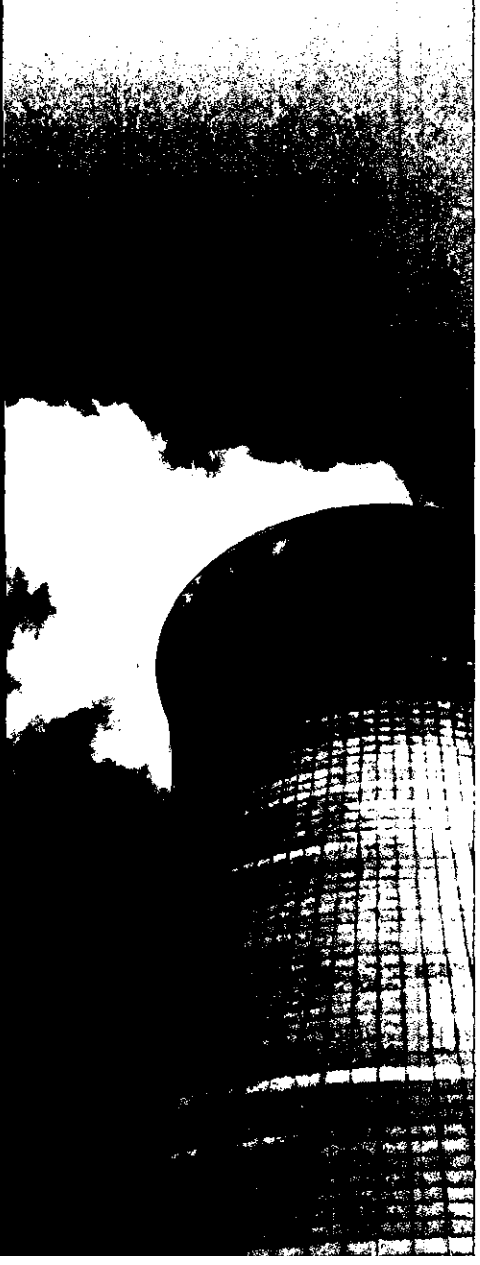
To meet growing wholesale and retail demand for electricity and achieve future milestones in generating performance, we are strategically adding capacity at our existing plants and exploring other opportunities for capacity additions.

Earlier this year, we purchased a partially complete, 707-megawatt (MW) natural gas, combined-cycle plant in Fremont, Ohio. We expect this plant to come online in two years, bringing our total capacity to nearly 15,000 MW. This new, low-emitting resource will further diversify our generation mix while reducing our average carbon dioxide (CO_2) emission rate – already about one-third below the average rate for generation in the region where our power plants are located.

Flue liners for the new Sammis Plant chimney

With completion of this facility, plant uprates and other strategic additions, we will have increased our generating capacity by more than 2,300 MW since 1999. That's the equivalent of our largest plant in Ohio, the W. H. Sammis Plant, and it was added at a fraction of the cost of a new plant.

In addition, the Nuclear Regulatory Commission accepted our application to renew the Beaver Valley Nuclear Power Station's license – an important first step toward keeping this vital asset operating well into the future.



Protecting the Environment

We continue to work aggressively to minimize the impact of our operations on the environment.

Since 1990, we've reconfigured our fleet by retiring older, less-efficient coal-based units and adding nuclear capacity while improving fleet efficiency. As a result, we have avoided some 150 million tons of CO_2 emissions. And, with nearly 40 percent

Little Blue Run containment pond

of our electricity generated by non-emitting resources – including more than 100 MW of wind capacity that came online in 2007 – we expect to be reasonably well-positioned to operate under carbon constraints that likely would be included in future climate change legislation.

Our environmental commitment is underscored by a major retrofit at our Sammis Plant – the centerpiece of our nearly $2 billion air quality compliance program. When this project is complete, 84 percent of the generation we control will be non-emitting or fully scrubbed. Environmental projects across our system are helping us achieve additional reductions in nitrogen-oxides and sulfur-dioxide emission rates, which are already significantly below the averages for our region.

As part of our ongoing support of emerging environmental technologies, we pledged $2 million to establish the FirstEnergy Advanced Energy Research Center at The University of Akron, expanding research involving carbon capture and coal-based fuel cells. And, we plan to continue supporting government and industry efforts to develop new carbon control technologies.

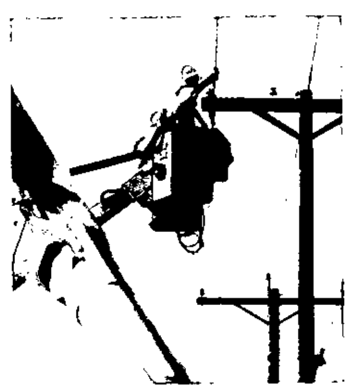
In addition, we launched new green energy programs to help customers support the development of alternative energy sources. For example, our Green Resource Program enables Ohio residential customers to purchase certificates that support renewable energy sources such as wind. We also offer load control programs, a project involving smart thermostats for residential customers, home energy audits and energy-efficiency rebates.

In Akron, a new office complex for about 700 Information Technology and FES employees will serve as a model of environmental stewardship. This facility is being built to the high standards set through Leadership in Energy and Environmental Design (LEED) specifications.

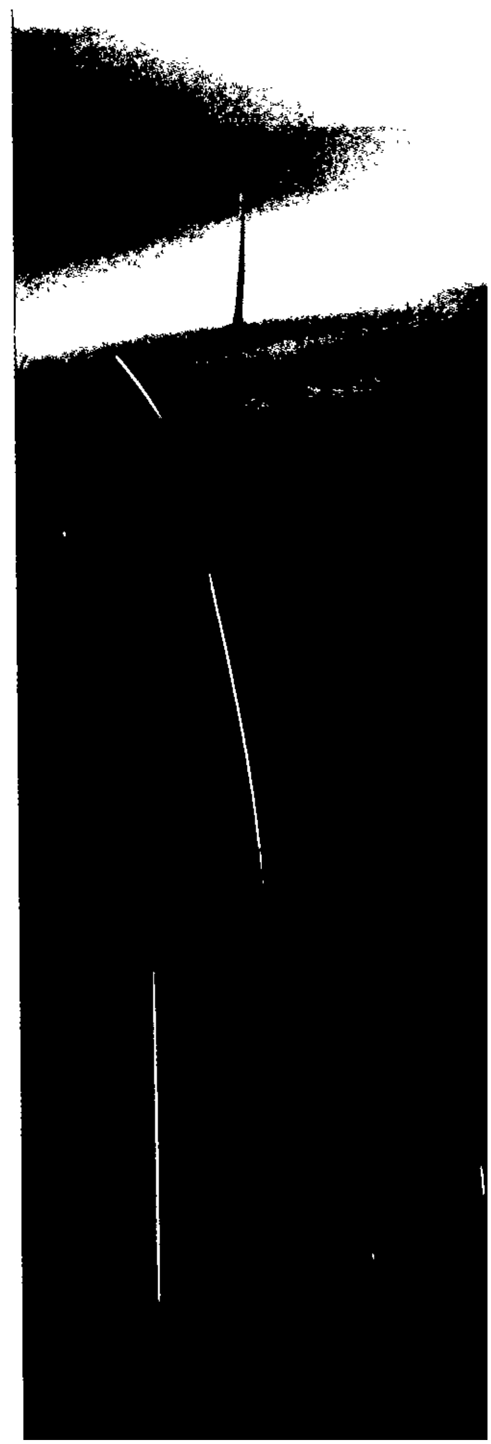
Enhancing Service to Customers

Through our ongoing investments in people, equipment and technology, we continue to enhance the reliability and responsiveness of our service to customers.

We've made significant investments in our transmission and distribution systems – adding new power lines, transformers, substations, trucks and other equipment. We've also installed new technologies that are designed



Line maintenance from a bucket truck



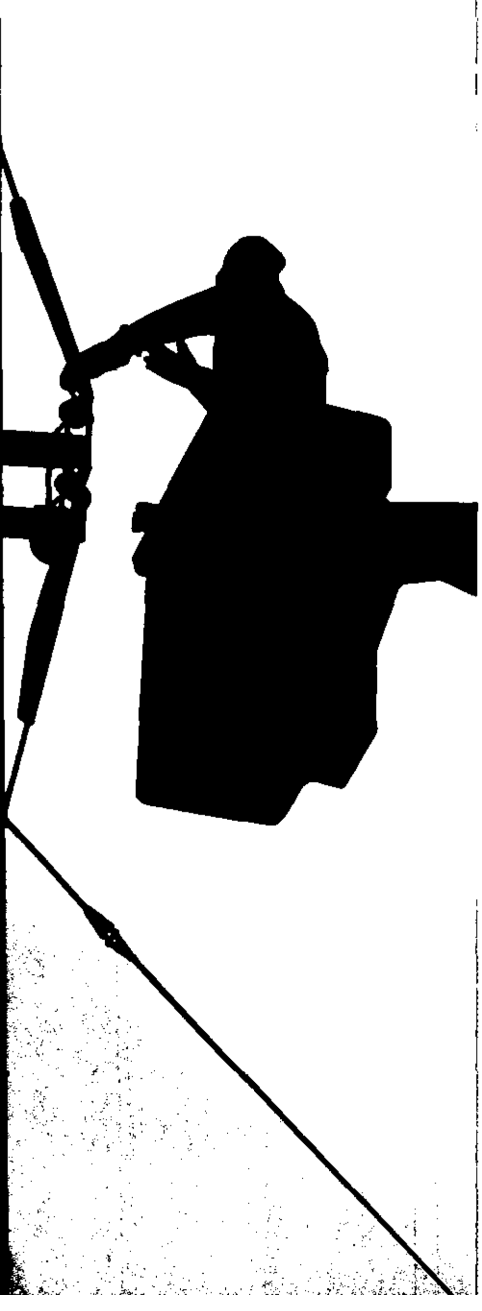
to reduce the number of customers affected by outages and help ensure faster service restoration when outages do occur.

These and other investments have produced significant results. For example, we have reduced the number of bulk-transmission outages by 25 percent over the past five years, and our system of high-voltage transmission lines again ranked among the industry's most reliable in 2007.

And, we continue to make progress in enhancing distribution reliability – cutting the average annual duration of outages by an hour, or 31 percent, over the past two years.

Our highly skilled employees remain among the best in our industry for emergency storm response. For the second consecutive year, we received the Edison Electric Institute's Emergency Assistance Award, which recognized our efforts to assist utilities in Indiana and Illinois with power restoration following some of the most damaging storms in more than a decade.

This dedication to service can be found throughout our Company. For example, our contact center representatives respond to nearly 10 million calls each year from customers who have questions and concerns. With the help of new equipment and processes, we're responding more quickly with accurate and timely information. In a survey of customers who contacted us, 81 percent rate the service they received a 9 or 10 on a 10-point scale.



Building Our Workforce and Our Communities

We're addressing a significant issue facing our Company and industry – the need to replace experienced employees who are approaching retirement age. In 2007, we welcomed nearly 1,300 new employees, and we plan to hire more than 1,000 people each year for the next five or more years.

PSI class on maintenance practices

As part of this effort, we recently expanded our innovative Power Systems Institute (PSI), which trains our next generation of line, substation and power plant employees by offering two-year associate degrees in applied science. We added three schools in 2007 and now have 550 students enrolled at the 11 colleges participating across our service area.

Beyond the employment opportunities available at our companies, we also help sustain local communities through the many contributions and volunteer efforts of our working men and women.

Among last year's charitable efforts, our employees and companies helped provide the equivalent of some two million meals to Harvest for Hunger and contributed $1.8 million to United Way organizations across Ohio, Pennsylvania and New Jersey. In addition, our FirstEnergy Foundation provided $5 million in grants to non-profit organizations across our service areas and in communities where our employees live and work.

We also support state and local economic development initiatives that work to attract and retain businesses and the jobs they create. In 2007, FirstEnergy was again recognized by *Site Selection* magazine as one of the top utilities in the country for promoting economic development. These and other efforts play a vital role in improving the business climate and quality of life in the communities we're privileged to serve.

Setting a Course for Future Growth

As we look toward the future, we are positioning our competitive generation business to achieve new operational milestones while helping meet growing customer demand for our product.

Clearly, energy efficiency and conservation efforts play a key role in helping us manage this demand. But our nation must add thousands of megawatts of new generation to keep pace with the growing need for electricity and to replace aging generating facilities. In fact, the Department of Energy has forecast that, by 2030, electricity use in the United States will increase by almost 40 percent.

Yet as an industry, we continue to face more demanding environmental requirements and a wide range of uncertainties that affect decisions to add capacity based on coal, advanced nuclear and other technologies. While we currently have no plans to add baseload generating facilities, we intend to employ cost-effective strategies in the near term to build on our diverse mix of environmentally sound generating assets.

I'm confident that our employees will meet these and other challenges that lie ahead. They've demonstrated an unwavering commitment to operational excellence while helping our Company achieve its financial and regulatory goals – and they are focused on delivering greater value to our shareholders and customers.

Along with recognizing the outstanding efforts of our employees, I thank you for your continued confidence as we enter our second decade as FirstEnergy. With your support, I remain dedicated to enhancing the value of your investment in the years ahead.

Sincerely,

Anthony J. Alexander

ANTHONY J. ALEXANDER
President and Chief Executive Officer

March 21, 2008

FIRSTENERGY BOARD OF DIRECTORS


Paul T. Addison


Anthony J. Alexander


Michael J. Anderson


Dr. Carol A. Cartwright


William T. Cottle


Robert B. Heisler, Jr.

Dear Shareholders:

On behalf of your Board of Directors, I want to thank FirstEnergy's management team and employees for another record year.

As a result of continued strong operational and financial performance, the market value of your Company increased by nearly $3 billion last year. Our 2007 total shareholder return of 23.6 percent, which reflects stock price appreciation plus reinvested dividends, was among the best in our industry. Based on our confidence in your Company's future, the Board increased the common stock dividend by an additional 10 percent in December, which brings the annual rate to $2.20 per share.

As FirstEnergy addresses its opportunities and challenges, we remain committed to rigorous standards of corporate governance and ethics. In February of this year, we were honored to be named among the top 100 Corporate Citizens in the United States by *Corporate Responsibility Officer (CRO) Magazine*. This prestigious annual study measures corporate efforts to address issues related to climate change, employee relations, environment, finance, governance, human rights, lobbying and philanthropy.

FirstEnergy's corporate governance practices also ranked among the top 10 percent of all utilities and the top 15 percent of all S&P 500 companies at the beginning of 2008, based on corporate governance measures used by ISS Governance Services.

You can learn more by reading our *Corporate Responsibility Report*, which offers a comprehensive look at your Company's ethics and governance practices, environmental commitment, health and safety issues, and contributions to our region's quality of life. The report is available online at *www.firstenergycorp.com.*

Your Board is proud of FirstEnergy's continued progress in enhancing value to shareholders and remains committed to ensuring that your interests are well represented.

Thank you for your ongoing confidence and support.

Sincerely,

GEORGE M. SMART
Chairman of the Board


Ernest J. Novak, Jr.


Catherine A. Rein


George M. Smart


Wes M. Taylor


Jesse T. Williams, Sr.

Paul T. Addison (61)
Retired, formerly Managing Director in the Utilities Department of Salomon Smith Barney (Citigroup). Chair, Finance Committee; Member, Audit Committee. Director of FirstEnergy Corp. since 2003.

Anthony J. Alexander (56)
President and Chief Executive Officer of FirstEnergy Corp. Director of FirstEnergy Corp. since 2002.

Michael J. Anderson (56)
President and Chief Executive Officer of The Andersons, Inc., and Chairman of the Board of Interstate Bakeries Corporation. Member, Finance and Nuclear Committees. Director of FirstEnergy Corp. since 2007.

Dr. Carol A. Cartwright (66)
Retired, formerly President of Kent State University. Chair, Corporate Governance Committee; Member, Compensation Committee. Director of FirstEnergy Corp. since 1997 and of Ohio Edison from 1992-1997.

William T. Cottle (62)
Retired, formerly Chairman of the Board, President and Chief Executive Officer of STP Nuclear Operating Company. Chair, Nuclear Committee; Member, Corporate Governance Committee. Director of FirstEnergy Corp. since 2003.

Robert B. Heisler, Jr. (59)
Special Assistant for Community and Business Strategies to the President of Kent State University; retired Chairman of the Board of KeyBank N.A. Member, Compensation and Finance Committees. Director of FirstEnergy Corp. from 1998-2004 and since 2006.

Ernest J. Novak, Jr. (63)
Retired, formerly Managing Partner of the Cleveland office of Ernst & Young LLP. Chair, Audit Committee; Member, Finance Committee. Director of FirstEnergy Corp. since 2004.

Catherine A. Rein (65)
Retired, formerly Senior Executive Vice President and Chief Administrative Officer of MetLife Inc. Chair, Compensation Committee; Member, Audit Committee. Director of FirstEnergy Corp. since 2001 and of the former GPU, Inc. (merged with FirstEnergy in 2001) from 1989-2001.

George M. Smart (62)
Non-executive Chairman of the FirstEnergy Corp. Board of Directors. Retired, formerly President of Sonoco-Phoenix, Inc. Member, Audit and Corporate Governance Committees. Director of FirstEnergy Corp. since 1997 and of Ohio Edison from 1988-1997.

Wes M. Taylor (65)
Retired, formerly President of TXU Generation. Member, Compensation and Nuclear Committees. Director of FirstEnergy Corp. since 2004.

Jesse T. Williams, Sr. (68)
Retired, formerly Vice President of Human Resources Policy, Employment Practices and Systems of The Goodyear Tire & Rubber Company. Member, Corporate Governance and Nuclear Committees. Director of FirstEnergy Corp. since 1997 and of Ohio Edison from 1992-1997.

FIRSTENERGY OFFICERS

FirstEnergy Corp.

Anthony J. Alexander
President and Chief Executive Officer

Mark T. Clark
Executive Vice President, Strategic Planning and Operations

Richard R. Grigg
Executive Vice President and President, FirstEnergy Utilities

Gary R. Leidich
Executive Vice President and President, FirstEnergy Generation

Leila L. Vespoli*
Executive Vice President and General Counsel

Richard H. Marsh*
Senior Vice President and Chief Financial Officer

James F. Pearson*
Vice President and Treasurer

Harvey L. Wagner*
Vice President, Controller and Chief Accounting Officer

Rhonda S. Ferguson*
Corporate Secretary

Paulette R. Chatman**
Assistant Controller

Jacqueline S. Cooper*
Assistant Corporate Secretary

Jeffrey R. Kalata*
Assistant Controller

Randy Scilla**
Assistant Treasurer

Edward J. Udovich**
Assistant Corporate Secretary

Lisa S. Wilson*
Assistant Controller

* *Also holds a similar position with FirstEnergy Service Company, FirstEnergy Solutions Corp., and FirstEnergy Nuclear Operating Company.*

** *Also holds a similar position with FirstEnergy Service Company and FirstEnergy Nuclear Operating Company.*

FirstEnergy Service Company

Anthony J. Alexander
President and Chief Executive Officer

Mark T. Clark
Executive Vice President, Strategic Planning and Operations

Richard R. Grigg
Executive Vice President and President, FirstEnergy Utilities

Gary R. Leidich
Executive Vice President and President, FirstEnergy Generation

Lynn M. Cavalier
Senior Vice President, Human Resources

David C. Luff
Senior Vice President, Governmental Affairs

Donald R. Schneider
Senior Vice President, Energy Delivery & Customer Service

Thomas M. Welsh
Senior Vice President, Assistant to CEO

Tony C. Banks
Vice President, Business Development, Performance & Management

David M. Blank
Vice President, Rates & Regulatory Affairs

William D. Byrd
Vice President, Corporate Risk and Chief Risk Officer

Mary Beth Carroll
Vice President, Corporate Affairs & Community Involvement

Thomas A. Clark
Vice President, Customer Service & Service Area Development

Ralph J. DiNicola
Vice President, Communications

Michael J. Dowling
Vice President, Governmental Affairs

Bradley S. Ewing
Vice President, Energy Delivery

Rhonda S. Ferguson
Vice President, Corporate Secretary and Chief Ethics Officer

Dennis J. Fuster
Vice President, Project Construction

Bennett L. Gaines
Vice President, Information Technology & Corporate Security, and Chief Information Officer

Mark A. Julian
Vice President, Energy Delivery

Nicholas J. Lizanich
Vice President, Asset Oversight

Thomas C. Navin
Vice President, Investment Management

John E. Paganie
Vice President, Energy Efficiency

Robert P. Reffner
Vice President, Legal

Ronald E. Seeholzer
Vice President, Investor Relations

Eugene J. Sitarz
Vice President, Tax

Daniel V. Steen
Vice President, Environmental

Stanley F. Szwed
Vice President, Federal Energy Regulatory Commission Policy, and Chief FERC Compliance Officer

Bradford F. Tobin
Vice President, Supply Chain, and Chief Procurement Officer

Richard J. Horak
Assistant Controller

FirstEnergy Solutions Corp.

Charles E. Jones
President

Ali Jamshidi
Vice President, Commodity Operations

Charles D. Lasky
Vice President, Fossil Operations

Arthur W. Yuan
Vice President, Sales & Marketing

Dennis J. Fuster†
Vice President

Frank A. Lubich†
Vice President, Fossil Operations

† *FirstEnergy Generation Corp.*

FirstEnergy Nuclear Operating Company

Anthony J. Alexander
Chief Executive Officer

Joseph J. Hagan
President and Chief Nuclear Officer

James H. Lash
Senior Vice President and Chief Operating Officer

Danny L. Pace
Senior Vice President, Fleet Engineering

Barry S. Allen
Vice President, Davis-Besse

Mark B. Bezilla
Vice President, Perry

Paul A. Harden
Vice President, Nuclear Support

Jeannie M. Rinckel
Vice President, Fleet Oversight

Peter P. Sena
Vice President, Beaver Valley

FirstEnergy Regional Operations Management

OHIO

James M. Murray
President, Ohio Operations

Dennis M. Chack
Regional President, The Cleveland Electric Illuminating Company

Trent A. Smith
Regional President, The Toledo Edison Company

Steven E. Strah
Regional President, Ohio Edison Company

PENNSYLVANIA

Douglas S. Elliott
President, Pennsylvania Operations

Ronald P. Lantzy
Regional President, Metropolitan Edison Company

James R. Napier, Jr.
Regional President, Pennsylvania Electric Company

NEW JERSEY

Stephen E. Morgan
President, Jersey Central Power & Light Company

Donald M. Lynch
Regional President, Jersey Central Power & Light Company

FIRSTENERGY FINANCIALS

The following financial information should be read in conjunction with, and is qualified in its entirety by reference to, the sections entitled "Management's Discussion and Analysis of Financial Condition and Results of Operations" and with the consolidated financial statements and the "Notes to Consolidated Financial Statements" in our 2007 Annual Report on Form 10-K (also included in our 2007 financial information package sent with our proxy materials for our 2008 Annual Meeting of Shareholders). Our Consolidated Statements of Income are not necessarily indicative of future conditions or results of operations.

SELECTED FINANCIAL DATA

For the Years Ended December 31,	2007	2006	2005	2004	2003
	(In millions, except per share amounts)				
Revenues	**$12,802**	$11,501	$11,358	$11,600	$10,802
Income From Continuing Operations	**$ 1,309**	$ 1,258	$ 879	$ 907	$ 494
Net Income	**$ 1,309**	$ 1,254	$ 861	$ 878	$ 423
Basic Earnings per Share of Common Stock:					
Income from continuing operations	**$ 4.27**	$ 3.85	$ 2.68	$ 2.77	$ 1.63
Net earnings per basic share	**$ 4.27**	$ 3.84	$ 2.62	$ 2.68	$ 1.39
Diluted Earnings per Share of Common Stock:					
Income from continuing operations	**$ 4.22**	$ 3.82	$ 2.67	$ 2.76	$ 1.62
Net earnings per diluted share	**$ 4.22**	$ 3.81	$ 2.61	$ 2.67	$ 1.39
Dividends Declared per Share of Common Stock [1]	**$ 2.05**	$ 1.85	$ 1.705	$1.9125	$ 1.50
Total Assets	**$32,068**	$31,196	$31,841	$31,035	$32,878
Capitalization as of December 31:					
Common Stockholders' Equity	**$ 8,977**	$ 9,035	$ 9,188	$ 8,590	$ 8,290
Preferred Stock	**–**	–	184	335	335
Long-Term Debt and Other Long-Term Obligations	**8,869**	8,535	8,155	10,013	9,789
Total Capitalization	**$17,846**	$17,570	$17,527	$18,938	$18,414
Weighted Average Number of Basic Shares Outstanding	**306**	324	328	327	304
Weighted Average Number of Diluted Shares Outstanding	**310**	327	330	329	305

[1] Dividends declared in 2007 include three quarterly payments of $0.50 per share in 2007 and one quarterly payment of $0.55 per share payable in 2008, increasing the indicated annual dividend rate from $2.00 to $2.20 per share. Dividends declared in 2006 include three quarterly payments of $0.45 per share in 2006 and one quarterly payment of $0.50 per share paid in 2007. Dividends declared in 2005 include two quarterly payments of $0.4125 per share in 2005, one quarterly payment of $0.43 per share in 2005 and one quarterly payment of $0.45 per share in 2006. Dividends declared in 2004 include four quarterly dividends of $0.375 per share paid in 2004 and a quarterly dividend of $0.4125 per share paid in 2005. Dividends declared in 2003 include four quarterly dividends of $0.375 per share.

PRICE RANGE OF COMMON STOCK

The common stock of FirstEnergy Corp. is listed on the New York Stock Exchange under the symbol "FE" and is traded on other registered exchanges.

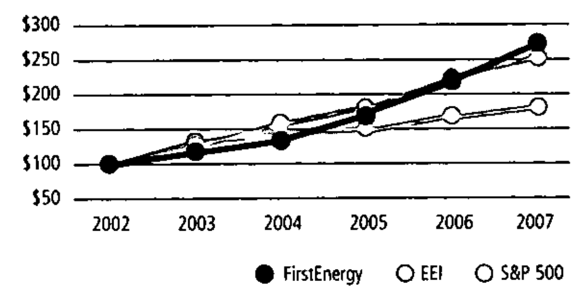
	2007		2006	
First Quarter High-Low	**$67.11**	**$57.77**	$52.17	$47.75
Second Quarter High-Low	**$72.90**	**$62.56**	$54.57	$48.23
Third Quarter High-Low	**$68.31**	**$58.75**	$57.50	$53.47
Fourth Quarter High-Low	**$74.98**	**$63.39**	$61.70	$55.99
Yearly High-Low	**$74.98**	**$57.77**	$61.70	$47.75

Prices are from http://finance.yahoo.com.

SHAREHOLDER RETURN

The following graph shows the total cumulative return from a $100 investment on December 31, 2002 in FirstEnergy's common stock compared with the total cumulative returns of the Edison Electric Institute's (EEI) Index of Investor-Owned Electric Utility Companies and the S&P 500.

Total Return Cumulative Values
($100 Investment on December 31, 2002)



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

Net income in 2007 was $1.31 billion, or basic earnings of $4.27 per share of common stock ($4.22 diluted), compared with net income of $1.25 billion, or basic earnings of $3.84 per share ($3.81 diluted) in 2006 and $861 million, or basic earnings of $2.62 per share ($2.61 diluted) in 2005. The increase in our 2007 earnings was driven primarily by increased electric sales revenues, partially offset by increased purchased power costs, increased other operating expenses and higher amortization of regulatory assets.

Change in Basic Earnings Per Share From Prior Year

	2007	2006	2005
Basic Earnings Per Share – Prior Year	**$3.84**	$2.62	$2.68
Non-core asset sales – 2007	**0.04**	–	–
Saxton decommissioning regulatory asset – 2007	**0.05**	–	–
Trust securities impairment – 2007/2006	**(0.03)**	(0.02)	–
PPUC NUG accounting adjustment – 2006	**0.02**	(0.02)	–
Ohio/New Jersey income tax adjustments – 2005	–	0.19	(0.19)
Sammis Plant New Source Review settlement – 2005	–	0.04	(0.04)
Davis-Besse fine/penalty – 2005	–	0.10	(0.10)
JCP&L arbitration decision – 2005	–	0.03	(0.03)
New regulatory assets - JCP&L settlement – 2005	–	(0.05)	0.05
Lawsuits settlements – 2004	–	–	0.03
Nuclear operations severance costs – 2004	–	–	0.01
Davis-Besse extended outage impacts – 2004	–	–	0.12
Discontinued Operations:			
Non-core asset sales/impairments	–	(0.02)	0.21
Other	**0.01**	(0.02)	(0.09)
Cumulative effect of a change in accounting principle	–	0.09	(0.09)
Revenues	**2.51**	0.26	(0.44)
Fuel and purchased power	**(1.51)**	(0.43)	0.72
Amortization of regulatory assets	**(0.31)**	0.78	(0.21)
Deferral of new regulatory assets	–	0.23	0.22
Other expenses	**(0.43)**	0.25	(0.27)
Investment income	**(0.03)**	(0.11)	0.02
Interest expense	**(0.11)**	(0.11)	0.02
Reduced common shares outstanding	**0.22**	0.03	–
Basic Earnings Per Share	**$4.27**	$3.84	$2.62

Total electric generation sales increased 2.5% during 2007 compared to the prior year, with retail and wholesale sales increasing 2.0%, and 4.5%, respectively. Electric distribution deliveries increased 2.6% in 2007 compared to 2006, reflecting load growth and higher weather-related usage in 2007.

Financial Matters

Dividends

On December 18, 2007, our Board of Directors declared a quarterly dividend of $0.55 per share on outstanding common stock, a 10% increase, payable on March 1, 2008. The new indicated annual dividend is $2.20 per share. This action brings our cumulative dividend increase to 47% since the beginning of 2005 and is consistent with our policy of sustainable annual dividend growth with a payout that is appropriate for our level of earnings.

Share Repurchase Programs

On March 2, 2007, we repurchased approximately 14.4 million shares, or 4.5%, of our outstanding common stock under an accelerated share repurchase program at an initial purchase price of approximately $900 million, or $62.63 per share. We paid a final purchase price adjustment in cash on December 13, 2007, resulting in a final purchase price of $942 million, or $65.54 per share.

On August 10, 2006, we repurchased approximately 10.6 million shares, or 3.2%, of our outstanding common stock through an accelerated share repurchase program. The initial purchase price was $600 million, or $56.44 per share. We paid a final purchase price adjustment of $27 million in cash on April 2, 2007. Under the two programs, we have repurchased approximately 25 million shares, or 8%, of the total common shares that were outstanding in July 2006.

Sale and Leaseback Transaction

On July 13, 2007, FirstEnergy Generation Corp. (FGCO) completed a $1.3 billion sale and leaseback transaction for its 779 MW interest in Unit 1 of the Bruce Mansfield Plant. The terms of the agreement provide for an approximate 33-year lease of Unit 1. We used the net, after-tax proceeds of approximately $1.2 billion to repay short-term debt that was used to fund the approximately $900 million share repurchase program and $300 million pension contribution. FES' registration obligations under the registration rights agreement applicable to the transaction were satisfied in September 2007, at which time the transaction was classified as an operating lease under Accounting principles generally accepted in the United States for FES and us. The $1.1 billion book gain from the transaction was deferred and will be amortized ratably over the lease term. FGCO continues to operate the plant under the terms of the lease agreement and is entitled to the plant's output.

Credit Rating Agency Action

On March 26, 2007, Standard & Poor's (S&P) assigned its corporate credit rating of BBB to FES and on March 27, 2007, Moody's issued a rating of Baa2 to FES. FES is the holding company of FGCO and FirstEnergy Nuclear Generating Corp. (NGC), the owners of our fossil and nuclear generation assets, respectively. Both S&P and Moody's cited the strength of our generation portfolio as a key contributor to the investment grade credit ratings.

On October 18, 2007, S&P revised their outlook for us and our subsidiaries to negative from stable, citing the exposure of our generating assets in Ohio and Pennsylvania to market commodity risk.

On November 2, 2007, Moody's revised their outlook for us and our subsidiaries to stable from positive, citing a downward trend in financial metrics, our near-term capital expenditure program and increased regulatory uncertainty.

Extension and Amendment of Credit Facility
On November 20, 2007, we and certain of our subsidiaries, agreed, pursuant to a Consent and Amendment with the lenders under our $2.75 billion credit facility dated as of August 24, 2006, to extend the termination date of the facility for one year to August 24, 2012. We also agreed to amendments that will permit us to request an unlimited number of additional one-year extensions of the facility termination date upon shorter notice than provided by the original facility terms, which permitted only two such extensions. In addition, the amendments increase FES' borrowing sub-limit under the credit facility to up to $1 billion and remove any requirements for the delivery of a parental guaranty of FES' obligations.

New Financings
On March 27, 2007, The Cleveland Electric Illuminating Company (CEI) issued $250 million of 5.70% unsecured senior notes due 2017. The proceeds from the transaction were used to repay short-term borrowings and for general corporate purposes.

On May 21, 2007, Jersey Central Power & Light Company (JCP&L) issued $550 million of senior unsecured debt securities. The offering was in two tranches, consisting of $250 million of 5.65% senior notes due 2017 and $300 million of 6.15% senior notes due 2037. The proceeds from the transaction were used to redeem all of JCP&L's outstanding First Mortgage Bonds, repay short-term debt and repurchase JCP&L's common stock from FirstEnergy.

On August 30, 2007, Pennsylvania Electric Company (Penelec) issued $300 million of 6.05% unsecured senior notes due 2017. A portion of the net proceeds from the issuance and sale of the senior notes was used to fund the repurchase of $200 million of Penelec's common stock from FirstEnergy. The remainder was used to repay short-term borrowings and for general corporate purposes.

On October 4, 2007, FGCO and NGC closed on the issuance of $427 million of Pollution Control Revenue Bonds (PCRBs). Proceeds from the issuance were used to redeem an equal amount of outstanding PCRBs originally issued on behalf of the Ohio Companies (Ohio Edison Company, CEI and The Toledo Edison Company). This transaction brings the total amount of PCRBs transferred from the Ohio Companies and Pennsylvania Power Company (Penn) to FGCO and NGC to approximately $1.9 billion, with approximately $265 million remaining to be transferred. The transfer of these PCRBs supports the intra-system generation asset transfer that was completed in 2005.

Regulatory Matters - Ohio

Legislative Process
On September 25, 2007, the Ohio Governor's proposed energy plan was officially introduced into the Ohio Senate as Senate Bill 221. The bill proposed to revise state energy policy to address electric generation pricing after 2008, establish advanced energy portfolio standards and energy efficiency standards, and create Greenhouse Gases emission reporting and carbon control planning requirements. The bill also proposed to move to a "hybrid" system for determining generation rates for default service in which electric utilities would provide regulated generation service unless they satisfy a statutory burden to demonstrate the existence of a competitive market for retail electricity.

The Senate Energy & Public Utilities Committee conducted hearings on the bill and received testimony from interested parties, including the Governor's Energy Advisor, the Chairman of the Public Utilities Commission of Ohio (PUCO), consumer groups, utility executives and others. On October 4, 2007, we provided testimony to the Committee citing several concerns with the introduced version of the bill, including its lack of context in which to establish prices. We recommended that the PUCO be provided the clear statutory authority to negotiate rate plans, and in the event that negotiations do not result in rate plan agreements, a competitive bidding process be utilized to establish generation prices for customers that do not choose alternative suppliers. We also proposed that the PUCO's statutory authority be expanded to promote societal programs such as energy efficiency, demand response, renewable power, and infrastructure improvements. Several proposed amendments to the bill were submitted, including those from Ohio's investor-owned electric utilities. On October 25, 2007, a substitute version of the bill, which incorporated certain of the proposed amendments, was introduced into the Senate Energy & Public Utilities Committee. On October 31, 2007, the Ohio Senate passed Substitute Senate Bill 221. Among other things, the bill outlines a process for establishing electricity generation prices beginning in 2009, and includes a requirement that at least 25% of the state's electricity come from advanced energy technologies by 2025, with at least one-half of that amount coming from renewable resources.

In November 2007, the Ohio House of Representatives referred the bill to the House Public Utilities Committee, which has since conducted various topic-based hearings on the bill. Testimony has been received from interested parties, including the Chairman of the PUCO, consumer groups, utility executives and others. On November 14, 2007, we provided testimony on the history and status of deregulation in Ohio. We said that Ohioans should have the opportunity to participate in the competitive electricity marketplace as provided for under Ohio's 1999 deregulation law, Senate Bill 3, which set the stage for long-term price moderation as well as more reliable and responsive service for Ohio's customers. On November 28, 2007, we provided further testimony expressing the industry's concerns with Substitute Senate Bill 221. We said the legislation should be modified to provide the PUCO with expanded regulatory tools and statutory authority to negotiate rate plans, and to include a true market rate option. At this time, we cannot predict the outcome of this process nor determine the impact, if any, such legislation may have on our operations.

Distribution Rate Request

On June 7, 2007, the Ohio Companies filed their base distribution rate increase request and supporting testimony with the PUCO. The requested increase of approximately $332 million in annualized distribution revenues (updated on August 6, 2007) is needed to recover expenses related to distribution operations and the costs deferred under previously approved rate plans. The new rates would become effective with the first billing cycle in January 2009 for Ohio Edison Company and The Toledo Edison Company, and approximately May 2009 for CEI. Concurrent with the effective dates of the proposed distribution rate increases, the Ohio Companies will reduce or eliminate their Regulatory Transition Charge revenues, resulting in an estimated net reduction of $262 million on the regulated portion of customers' bills.

On December 4, 2007, the PUCO Staff issued its Staff Reports containing the results of their investigation into the distribution rate request. In its reports, the PUCO Staff recommended a distribution rate increase in the range of $161 million to $180 million, compared to the Ohio Companies' request of $332 million. On January 3, 2008, the Ohio Companies and intervening parties filed objections to the Staff Reports and on January 10, 2008, the Ohio Companies filed supplemental testimony. Evidentiary hearings began on January 29, 2008 and continued through February 2008. During the evidentiary hearings, the PUCO Staff submitted testimony decreasing their recommended revenue increase to a range of $114 million to $132 million. The PUCO is expected to render its decision during the second or third quarter of 2008.

Generation Supply Proposal

On July 10, 2007, the Ohio Companies filed an application with the PUCO requesting approval of a comprehensive supply plan for providing generation service to customers who do not purchase electricity from an alternative supplier, beginning January 1, 2009. The proposed competitive bidding process would average the results of multiple bidding sessions conducted at different times during the year. The final price per kilowatt-hour (KWH) included in rates would reflect an average of the prices resulting from all successful bid sessions. In their filing, the Ohio Companies offered two alternatives for structuring the bids, either by customer class or a "slice-of-system" approach. A slice-of-system approach would require the successful bidder to be responsible for supplying a fixed percentage of the utility's total load notwithstanding the customer's classification. The proposal also provides the PUCO with the option to phase in generation price increases for any residential tariff group if the outcome of a bid would otherwise result in an increase in average total price of 15% or more. On August 16, 2007, the PUCO held a technical conference for interested parties to gain a better understanding of the proposal. Initial and reply comments on the proposal were filed by various parties in September and October, 2007, respectively. The proposal is currently pending before the PUCO.

RCP Fuel Remand

On August 29, 2007, the Supreme Court of Ohio upheld findings by the PUCO, approving several provisions of the Ohio Companies' Rate Certainty Plan (RCP). The Court, however, remanded back to the PUCO for further consideration the portion of the PUCO's RCP order that authorized the Ohio Companies to collect deferred fuel costs through future distribution rates. The Court found recovery of competitive generation service costs through noncompetitive distribution rates unlawful. The PUCO's order had authorized the Ohio Companies to defer increased fuel costs incurred from January 1, 2006 through December 31, 2008, including interest on the deferred balances, and to recover these deferred costs over a 25-year period beginning in 2009. On September 7, 2007, the Ohio Companies filed a Motion for Reconsideration with the Court on the issue of the deferred fuel costs, which the Court later denied on November 21, 2007. On September 10, 2007, the Ohio Companies filed an Application on remand with the PUCO proposing that the increased fuel costs be recovered through two generation-related fuel cost recovery riders during the period of October 2007 through December 2008. On January 9, 2008 the PUCO approved the Ohio Companies' proposed fuel cost rider to recover fuel costs incurred from January 1, 2008 through December 31, 2008, which is expected to be approximately $167 million. The fuel cost rider was effective January 11, 2008 and will be adjusted and reconciled quarterly. In addition, the PUCO ordered the Ohio Companies to file a separate application for an alternate recovery mechanism to collect the 2006 and 2007 deferred fuel costs. On February 8, 2008, the Ohio Companies filed an application proposing to recover $220 million of deferred fuel costs and carrying charges for 2006 and 2007 pursuant to a separate fuel rider, with alternative options for the recovery period ranging from 5 to 25 years. This second application is pending before the PUCO.

Renewable Energy Option

On August 15, 2007, the PUCO approved a stipulation filed by the Ohio Companies, PUCO Staff and the Ohio Consumers' Counsel that creates a green pricing option for customers of the Ohio Companies. The Green Resource Program enables customers to support the development of alternative energy resources through their voluntary participation in this alternative to the Ohio Companies' standard service offer for generation supply. The Green Resource Program provides for the Ohio Companies to purchase Renewable Energy Certificates at prices determined through a competitive bidding process monitored by the PUCO.

Regulatory Matters – Pennsylvania

Legislative Process
On February 1, 2007, the Governor of Pennsylvania proposed an Energy Independence Strategy (EIS). The EIS includes four pieces of proposed legislation that, according to the Governor, are designed to reduce energy costs, promote energy independence and stimulate the economy. Elements of the EIS include the installation of smart meters, funding for solar panels on residences and small businesses, conservation and demand reduction programs to meet energy growth, a requirement that electric distribution companies acquire power that results in the "lowest reasonable rate on a long-term basis," the utilization of micro-grids and a three year phase-in of rate increases.

On July 17, 2007 the Governor signed into law two pieces of energy legislation. The first amended the Alternative Energy Portfolio Standards Act of 2004 to, among other things, increase the percentage of solar energy that must be supplied at the conclusion of an electric distribution company's transition period. The second law allows electric distribution companies, at their sole discretion, to enter into long-term contracts with large customers and to build or acquire interests in electric generation facilities specifically to supply long-term contracts with such customers. A special legislative session on energy was convened in mid-September 2007 to consider other aspects of the EIS. The final form of any legislation arising from the special legislative session is uncertain. Consequently, we are unable to predict what impact, if any, such legislation may have on our operations.

Penn's Interim Default Service Supply
On May 2, 2007, Penn made a filing with the Pennsylvania Public Utility Commission (PPUC) proposing how it will procure the power supply needed for default service customers beginning June 1, 2008. Penn's customers transitioned to a fully competitive market on January 1, 2007, and the default service plan that the PPUC previously approved covered a 17-month period through May 31, 2008. The filing proposed that Penn procure a full-requirements product, by customer class, through multiple Request for Proposals (RFPs) with staggered delivery periods extending through May 2011. It also proposed a 3-year phase-out of promotional generation rates.

On September 28, 2007, Penn filed a Joint Petition for Settlement resolving all but one issue in the case. Briefs were also filed on September 28, 2007 on the unresolved issue of incremental uncollectible accounts expense. The settlement was either supported, or not opposed, by all parties. On December 20, 2007, the PPUC approved the settlement except for the full requirements tranche approach for residential customers, which was remanded to the Administrative Law Judge for further proceedings. Under the terms of the Settlement Agreement, the default service procurement for small commercial customers will be done with multiple RFPs, while the default service procurement for large commercial and industrial customers will utilize hourly pricing. Bids in the first RFP for small commercial load were received on February 20, 2008. In February 2008, parties filed direct and rebuttal testimony in the remand proceeding for the residential procurement approach. An evidentiary hearing was held on February 26, 2008, and this matter is expected to be presented to the PPUC for its consideration by March 13, 2008.

Commonwealth Court Appeal
On January 11, 2007, the PPUC issued its order in the Metropolitan Edison Company (Met-Ed) and Penelec 2006 comprehensive transition rate cases. Met-Ed and Penelec subsequently appealed the PPUC's decision on the denial of generation rate relief and on a consolidated income tax adjustment related to the cost of capital to the Pennsylvania Commonwealth Court, while other parties appealed the PPUC's decision on transmission rate relief to that court. Initial briefs in the appeals were filed on June 19, 2007. Responsive briefs and reply briefs were filed on September 21, 2007 and October 5, 2007, respectively. Oral arguments are expected to take place in early 2008.

Generation

Our generating fleet produced 81.0 billion KWH during 2007 compared to 82.0 billion KWH in 2006. Our nuclear fleet produced a record 30.3 billion KWH, while the non-nuclear fleet produced 50.7 billion KWH.

During 2007, generation capacity at several of our units increased as a result of work completed in connection with outages for refueling or other maintenance. These capacity additions were achieved in support of our operating strategy to maximize existing generation assets. The resulting increases in the net demonstrated capacity of our generating units are summarized below:

2007 Power Uprates (MW)

Fossil:	
Bruce Mansfield Unit 3	30
Seneca Unit 2	8
	38
Nuclear:	
Beaver Valley Unit 1	43
Beaver Valley Unit 2	24
	67
Total	**105**

Our supply portfolio was also enhanced during the year through the reduction of seasonal derates by 149 MW at our peaking units and through long-term contracts to purchase the output of 115 MW from wind generators.

Complementing our strategy of incremental enhancements to our current generating fleet, FGCO identified an opportunity to acquire a partially completed 707-MW natural gas fired generating plant in Fremont, Ohio. On January 28, 2008, FGCO entered into definitive agreements with Calpine Corporation to acquire the plant for $253.6 million, following a competitive bid process. The facility includes two combined-cycle combustion turbines and a steam turbine which are expected to be capable of producing approximately 544 MW of load-following capacity and 163 MW of peaking capacity. In court documents, Calpine has estimated that the plant is 70% complete and could become operational within 12 to 18 months. Based on those documents, FGCO estimates that the additional expenditures to complete the facility to be approximately $150 million to $200 million. The final cost and timeframe for construction are subject to FGCO's pending engineering study.

Environmental Update

In February 2007, a Selective Non-Catalytic Reduction (SNCR) system was placed in-service at Unit 5 of FGCO's Eastlake Plant, upon completion of a scheduled maintenance outage. The SNCR installation is part of our overall Air Quality Compliance Strategy and was required under the New Source Review Consent Decree. The SNCR system is expected to reduce Nitrogen Oxide (NOx) emissions and help achieve reductions required by the United States Environmental Protection Agency's NOx Transport Rule.

On May 30, 2007, we announced that FGCO plans to install an Electro-Catalytic Oxidation (ECO) system on Units 4 and 5 of the R.E. Burger Plant. Design engineering for the new Burger Plant ECO system began in 2007 with anticipated start-up in the first quarter of 2011.

Perry Nuclear Power Plant

On March 2, 2007, the Nuclear Regulatory Commission (NRC) returned the Perry Plant to routine agency oversight as a result of its assessment of the corrective actions that FirstEnergy Nuclear Operating Company (FENOC) has taken over the last two-and-one-half years. The plant had been operating under heightened NRC oversight since August 2004. On May 8, 2007, as a result of a "white" Emergency AC Power Systems mitigating systems performance indicator, the NRC notified FENOC that the Perry Plant was being placed in the Regulatory Response Column (Column 2 of the Reactor Oversight Process) and additional inspections would be conducted.

On June 29, 2007, the Perry Plant began an unplanned outage to replace a 30-ton motor in the reactor recirculation system. In addition to the motor replacement, routine and preventive maintenance and several system inspections were performed during the outage to assure continued safe and reliable operation of the plant. On July 25, 2007, the plant was returned to service.

On August 21, 2007, FENOC announced plans to expand used nuclear fuel storage capacity at the Perry Plant. The plan calls for installing above-ground, airtight steel and concrete cylindrical canisters, cooled by natural air circulation, to store used fuel assemblies. Construction of the new fuel storage system, which is expected to cost approximately $30 million, is scheduled to begin in the spring of 2008, with completion planned for 2010.

Beaver Valley Power Station

On October 24, 2007, Beaver Valley Unit 1 returned to service following completion of its scheduled refueling outage that began on September 24, 2007. During the outage, the ten-year in-service inspection of the reactor vessel was also completed with no significant issues identified. Beaver Valley Unit 1 had operated for 378 consecutive days when it was taken off line for the outage.

In August 2007, FENOC filed applications with the NRC seeking renewal of the operating licenses for Beaver Valley Units 1 and 2 for an additional 20 years, which would extend the operating licenses to January 29, 2036, for Unit 1 and May 27, 2047, for Unit 2. On November 9, 2007, FENOC announced that the NRC's preliminary requirements to extend the licenses had been met. The NRC held a public meeting on November 27, 2007 to discuss the license renewal. Over the next two years, the NRC will conduct audits and an environmental survey. A decision on the applications is expected in the third quarter of 2009.

Davis-Besse Nuclear Power Station

On May 14, 2007, the NRC issued a Demand for Information (DFI) to FENOC regarding two reports prepared by expert witnesses for an insurance arbitration related to Davis-Besse. On June 13, 2007, FENOC filed a response to the NRC's DFI reaffirming that it accepts full responsibility for the mistakes and omissions leading up to the damage to the reactor vessel head and that it remains committed to operating Davis-Besse and our other nuclear plants safely and responsibly. In follow-up discussions, FENOC was asked to provide supplemental information to clarify certain aspects of the DFI response and provide additional details regarding plans to implement the commitments made therein. FENOC submitted this supplemental response to the NRC on July 16, 2007. On August 15, 2007, the NRC issued a confirmatory order imposing these commitments. FENOC must inform the NRC's Office of Enforcement after it completes the key commitments embodied in the NRC's order. FENOC's compliance with these commitments is subject to future NRC review.

On February 14, 2008, Davis-Besse returned to service following completion of its scheduled refueling outage, which began on December 30, 2007. In addition to replacing 76 of the 177 fuel assemblies, several improvement projects were completed, including rewinding the turbine generator and reinforcing welds on plant equipment.

CONSOLIDATED STATEMENTS OF INCOME

For the Years Ended December 31,	2007	2006	2005
	(In millions, except per share amounts)		
Revenues:			
Electric utilities	**$11,305**	$10,007	$9,703
Unregulated businesses	**1,497**	1,494	1,655
Total revenues*	**12,802**	11,501	11,358
Expenses:			
Fuel and purchased power	**5,014**	4,253	4,011
Other operating expenses	**3,086**	2,965	3,103
Provision for depreciation	**638**	596	588
Amortization of regulatory assets	**1,019**	861	1,281
Deferral of new regulatory assets	**(524)**	(500)	(405)
General taxes	**754**	720	713
Total expenses	**9,987**	8,895	9,291
Operating Income	**2,815**	2,606	2,067
Other Income (Expense):			
Investment income	**120**	149	217
Interest expense	**(775)**	(721)	(660)
Capitalized interest	**32**	26	19
Subsidiaries' preferred stock dividends	**–**	(7)	(15)
Total other expense	**(623)**	(553)	(439)
Income From Continuing Operations Before Income Taxes	**2,192**	2,053	1,628
Income Taxes	**883**	795	749
Income From Continuing Operations	**1,309**	1,258	879
Discontinued operations (net of income tax benefits of $2 million and $4 million, respectively)	**–**	(4)	12
Income Before Cumulative Effect Of A Change In Accounting Principle	**1,309**	1,254	891
Cumulative effect of a change in accounting principle (net of income tax benefit of $17 million)	**–**	–	(30)
Net Income	**$ 1,309**	$ 1,254	$ 861
Basic Earnings Per Share Of Common Stock:			
Income from continuing operations	**$ 4.27**	$ 3.85	$ 2.68
Discontinued operations	**–**	(0.01)	0.03
Cumulative effect of a change in accounting principle	**–**	–	(0.09)
Net earnings per basic share	**$ 4.27**	$ 3.84	$ 2.62
Weighted Average Number Of Basic Shares Outstanding	**306**	324	328
Diluted Earnings Per Share Of Common Stock:			
Income from continuing operations	**$ 4.22**	$ 3.82	$ 2.67
Discontinued operations	**–**	(0.01)	0.03
Cumulative effect of a change in accounting principle	**–**	–	(0.09)
Net earnings per diluted share	**$ 4.22**	$ 3.81	$ 2.61
Weighted Average Number Of Diluted Shares Outstanding	**310**	327	330

* *Includes $424 million, $400 million and $395 million of excise tax collections in 2007, 2006 and 2005, respectively.*

CONSOLIDATED BALANCE SHEETS

As of December 31,	2007	2006
ASSETS	*(In millions)*	
Current Assets:		
Cash and cash equivalents	$ 129	$ 90
Receivables-		
Customers (less accumulated provisions of $36 million and $43 million, respectively, for uncollectible accounts)	1,256	1,135
Other (less accumulated provisions of $22 million and $24 million, respectively, for uncollectible accounts)	165	132
Materials and supplies, at average cost	521	577
Prepayments and other	159	149
	2,230	2,083
Property, Plant And Equipment:		
In service	24,619	24,105
Less - Accumulated provision for depreciation	10,348	10,055
	14,271	14,050
Construction work in progress	1,112	617
	15,383	14,667
Investments:		
Nuclear plant decommissioning trusts	2,127	1,977
Investments in lease obligation bonds	717	811
Other	754	746
	3,598	3,534
Deferred Charges And Other Assets:		
Goodwill	5,607	5,898
Regulatory assets	3,945	4,441
Pension assets	700	-
Other	605	573
	10,857	10,912
	$32,068	$31,196
LIABILITIES AND CAPITALIZATION		
Current Liabilities:		
Currently payable long-term debt	$ 2,014	$ 1,867
Short-term borrowings	903	1,108
Accounts payable	777	726
Accrued taxes	408	598
Other	1,046	956
	5,148	5,255
Capitalization:		
Common stockholders' equity	8,977	9,035
Long-term debt and other long-term obligations	8,869	8,535
	17,846	17,570
Noncurrent Liabilities:		
Accumulated deferred income taxes	2,671	2,740
Asset retirement obligations	1,267	1,190
Deferred gain on sale and leaseback transaction	1,060	-
Power purchase contract loss liability	750	1,182
Retirement benefits	894	944
Lease market valuation liability	663	767
Other	1,769	1,548
	9,074	8,371
	$32,068	$31,196

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY

(Dollars in millions)

	COMPREHENSIVE INCOME	COMMON STOCK NUMBER OF SHARES	COMMON STOCK PAR VALUE	OTHER PAID-IN CAPITAL	ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)	RETAINED EARNINGS	UNALLOCATED ESOP COMMON STOCK
Balance, January 1, 2005		329,836,276	$33	$7,056	$(313)	$1,857	$(43)
Net income	$ 861					861	
Minimum liability for unfunded retirement benefits, net of $208 million of income taxes	295				295		
Unrealized gain on derivative hedges, net of $9 million of income taxes	14				14		
Unrealized loss on investments, net of $15 million of income tax benefits	(16)				(16)		
Comprehensive income	$1,154						
Stock options exercised				(41)			
Allocation of ESOP shares				22			16
Restricted stock units				6			
Cash dividends declared on common stock						(559)	
Balance, December 31, 2005		329,836,276	33	7,043	(20)	2,159	(27)
Net income	$1,254					1,254	
Unrealized gain on derivative hedges, net of $10 million of income taxes	19				19		
Unrealized gain on investments, net of $40 million of income taxes	69				69		
Comprehensive income	$1,342						
Net liability for unfunded retirement benefits due to the implementation of SFAS 158, net of $292 million of income tax benefits					(327)		
Redemption premiums on preferred stock						(9)	
Stock options exercised				(28)			
Allocation of ESOP shares				33			17
Restricted stock units				11			
Stock based compensation				6			
Repurchase of common stock		(10,630,759)	(1)	(599)			
Cash dividends declared on common stock						(598)	
Balance, December 31, 2006		319,205,517	32	6,466	(259)	2,806	(10)
Net income	$1,309					1,309	
Unrealized loss on derivative hedges, net of $8 million of income tax benefits	(17)				(17)		
Unrealized gain on investments, net of $31 million of income taxes	47				47		
Pension and other postretirement benefits, net of $169 million of income taxes	179				179		
Comprehensive income	$1,518						
Stock options exercised				(40)			
Allocation of ESOP shares				26			10
Restricted stock units				23			
Stock based compensation				2			
FIN 48 cumulative effect adjustment						(3)	
Repurchase of common stock		(14,370,110)	(1)	(968)			
Cash dividends declared on common stock						(625)	
Balance, December 31, 2007		304,835,407	$31	$5,509	$ (50)	$3,487	$ –

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31,	**2007**	2006	2005
		(In millions)	
Cash Flows From Operating Activities:			
Net income	**$1,309**	$1,254	$861
Adjustments to reconcile net income to net cash from operating activities-			
Provision for depreciation	**638**	596	588
Amortization of regulatory assets	**1,019**	861	1,281
Deferral of new regulatory assets	**(524)**	(500)	(405)
Nuclear fuel and lease amortization	**101**	90	90
Deferred purchased power and other costs	**(346)**	(445)	(384)
Deferred income taxes and investment tax credits, net	**(9)**	159	154
Investment impairment	**26**	27	6
Cumulative effect of a change in accounting principle	**-**	-	30
Deferred rents and lease market valuation liability	**(99)**	(113)	(104)
Accrued compensation and retirement benefits	**(37)**	193	90
Tax refunds related to pre-merger period	**-**	-	18
Commodity derivative transactions, net	**6**	24	6
Gain on asset sales	**(30)**	(49)	(35)
Loss (income) from discontinued operations	**-**	4	(12)
Cash collateral, net	**(68)**	(77)	196
Pension trust contributions	**(300)**	-	(500)
Decrease (increase) in operating assets-			
Receivables	**(136)**	105	(87)
Materials and supplies	**79**	(25)	(32)
Prepayments and other current assets	**10**	3	3
Increase (decrease) in operating liabilities-			
Accounts payable	**51**	99	32
Accrued taxes	**71**	(175)	150
Accrued interest	**(8)**	7	(6)
Electric service prepayment programs	**(75)**	(64)	208
Other	**16**	(35)	72
Net cash provided from operating activities	**1,694**	1,939	2,220
Cash Flows From Financing Activities:			
New Financing-			
Long-term debt	**1,527**	2,739	721
Short-term borrowings, net	**-**	386	561
Redemptions and Repayments-			
Common stock	**(969)**	(600)	-
Preferred stock	**-**	(193)	(170)
Long-term debt	**(1,098)**	(2,536)	(1,424)
Short-term borrowings, net	**(205)**	-	-
Net controlled disbursement activity	**(1)**	(27)	(18)
Stock-based compensation tax benefit	**20**	13	-
Common stock dividend payments	**(616)**	(586)	(546)
Net cash used for financing activities	**(1,342)**	(804)	(876)
Cash Flows From Investing Activities:			
Property additions	**(1,633)**	(1,315)	(1,208)
Proceeds from asset sales	**42**	162	104
Proceeds from sale and leaseback transaction	**1,329**	-	-
Sales of investment securities held in trusts	**1,294**	1,651	1,587
Purchases of investment securities held in trusts	**(1,397)**	(1,666)	(1,688)
Cash investments and restricted funds	**72**	121	(42)
Other	**(20)**	(62)	(86)
Net cash used for investing activities	**(313)**	(1,109)	(1,333)
Net increase in cash and cash equivalents	**39**	26	11
Cash and cash equivalents at beginning of year	**90**	64	53
Cash and cash equivalents at end of year	**$129**	$90	$64
Supplemental Cash Flow Information:			
Cash Paid During the Year-			
Interest (net of amounts capitalized)	**$744**	$656	$665
Income taxes	**$710**	$688	$406

Transfer Agent and Registrar

FirstEnergy Securities Transfer Company, a subsidiary of FirstEnergy, acts as the transfer agent and registrar. Shareholders wanting to transfer stock, or who need assistance or information, can send their stock or write to Shareholder Services, FirstEnergy Corp., 76 South Main Street, Akron, Ohio 44308-1890. Shareholders also can call the following toll-free telephone number, which is valid in the United States, Canada, Puerto Rico and the Virgin Islands, weekdays between 8:00 a.m. and 4:30 p.m., Eastern Time: 1-800-736-3402. For Internet access to general shareholder information and useful forms, visit our Web site at *www.firstenergycorp.com/ir.*

Stock Listing and Trading

Newspapers generally report FirstEnergy common stock under the abbreviation FSTENGY, but this can vary depending upon the newspaper. The common stock of FirstEnergy is listed on the New York Stock Exchange under the symbol FE.

Direct Dividend Deposit

Shareholders can have their dividend payments automatically deposited to checking and savings accounts at any financial institution that accepts electronic direct deposits. Using this free service ensures that payments will be available to you on the payment date, eliminating the possibility of mail delay or lost checks. Contact Shareholder Services to receive an authorization form.

Stock Investment Plan

Shareholders and others can purchase or sell shares of FirstEnergy common stock through the Company's Stock Investment Plan. Investors who are not registered shareholders can enroll with an initial $250 investment. Participants can invest all or some of their dividends or make optional payments at any time of at least $25 per payment up to $100,000 annually. Contact Shareholder Services to receive an enrollment form.

Safekeeping of Shares

Shareholders can request that the Company hold their shares of FirstEnergy common stock in safekeeping. To take advantage of this service, shareholders should forward their common stock certificates to the Company along with a signed letter requesting that the Company hold the shares. Shareholders also should state whether future dividends for the held shares are to be reinvested or paid in cash. The certificates should not be endorsed, and registered mail is suggested. The shares will be held in uncertificated form, and we will make certificates available to shareholders upon request at no cost. Shares held in safekeeping will be reported on dividend checks or Stock Investment Plan statements.

Form 10-K Annual Report

Form 10-K, the Annual Report to the Securities and Exchange Commission, will be sent to you without charge upon written request to Rhonda S. Ferguson, Corporate Secretary, FirstEnergy Corp., 76 South Main Street, Akron, Ohio 44308-1890. You can also view the Form 10-K by visiting the Company's Internet site at *www.firstenergycorp.com/ir.*

Institutional Investor and Security Analyst Inquiries

Institutional investors and security analysts should direct inquiries to: Ronald E. Seeholzer, Vice President, Investor Relations, 330-384-5415.

Annual Meeting of Shareholders

Shareholders are invited to attend the 2008 Annual Meeting of Shareholders on Tuesday, May 20, at 10:30 a.m. Eastern Time, at the John S. Knight Center, 77 East Mill Street, in Akron, Ohio. Registered shareholders not attending the meeting can appoint a proxy and vote on the items of business by telephone, Internet or by completing and returning the proxy card that is sent to them. Shareholders whose shares are held in the name of a broker can attend the meeting if they present a letter from their broker indicating ownership of FirstEnergy common stock on the record date of March 21, 2008.

FirstEnergy has included as Exhibit 31 to its Annual Report on Form 10-K for fiscal year 2007 filed with the Securities and Exchange Commission certificates of FirstEnergy's Chief Executive Officer and Chief Financial Officer certifying the quality of the Company's public disclosure. FirstEnergy's Chief Executive Officer has also submitted to the New York Stock Exchange (NYSE) a certificate certifying that he was not aware of any violation by FirstEnergy of the NYSE corporate governance listing standards as of the date of the certification.

This report was printed on recycled paper using 10% post-consumer waste.

FirstEnergy

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SUMMARY

2007 ANNUAL REPORT

2007 FINANCIAL INFORMATION

FirstEnergy®

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GLOSSARY OF TERMS

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

ATSI	American Transmission Systems, Inc., owns and operates transmission facilities
CEI	The Cleveland Electric Illuminating Company, an Ohio electric utility operating subsidiary
Centerior	Centerior Energy Corporation, former parent of CEI and TE, which merged with OE to form FirstEnergy on November 8, 1997
Companies	OE, CEI, TE, Penn, JCP&L, Met-Ed and Penelec
FENOC	FirstEnergy Nuclear Operating Company, operates nuclear generating facilities
FES	FirstEnergy Solutions Corp., provides energy-related products and services
FESC	FirstEnergy Service Company, provides legal, financial and other corporate support services
FGCO	FirstEnergy Generation Corp., owns and operates non-nuclear generating facilities
FirstEnergy	FirstEnergy Corp., a public utility holding company
FSG	FirstEnergy Facilities Services Group, LLC, former parent of several heating, ventilation, air conditioning and energy management companies
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, a New Jersey electric utility operating subsidiary
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, a Pennsylvania electric utility operating subsidiary
MYR	MYR Group, Inc., a utility infrastructure construction service company
NGC	FirstEnergy Nuclear Generation Corp., owns nuclear generating facilities
OE	Ohio Edison Company, an Ohio electric utility operating subsidiary
Ohio Companies	CEI, OE and TE
Pennsylvania Companies	Met-Ed, Penelec and Penn
Penelec	Pennsylvania Electric Company, a Pennsylvania electric utility operating subsidiary
Penn	Pennsylvania Power Company, a Pennsylvania electric utility operating subsidiary of OE
PNBV	PNBV Capital Trust, a special purpose entity created by OE in 1996
Shippingport	Shippingport Capital Trust, a special purpose entity created by CEI and TE in 1997
TE	The Toledo Edison Company, an Ohio electric utility operating subsidiary
TEBSA	Termobarranquilla S.A., Empresa de Servicios Publicos

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

AEP	American Electric Power Company, Inc.
ALJ	Administrative Law Judge
AOCL	Accumulated Other Comprehensive Loss
APB	Accounting Principles Board
APB 25	APB Opinion No. 25, "Accounting for Stock Issued to Employees"
APIC	Additional Paid-In Capital
AQC	Air Quality Control
ARB	Accounting Research Bulletin
ARO	Asset Retirement Obligation
BCIDA	Beaver County Industrial Development Authority (Pennsylvania)
BGS	Basic Generation Service
BPJ	Best Professional Judgment
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CAT	Commercial Activity Tax
CAVR	Clean Air Visibility Rule
CBP	Competitive Bid Process
CO_2	Carbon Dioxide
CTC	Competitive Transition Charge
DCPD	Deferred Compensation Plan for Outside Directors

GLOSSARY OF TERMS Cont'd.

DFI	Demand for information
DOE	United States Department of Energy
DOJ	United States Department of Justice
DRA	Division of Ratepayer Advocate
ECAR	East Central Area Reliability Coordination Agreement
ECO	Electro-Catalytic Oxidation
EDCP	Executive Deferred Compensation Plan
EEI	Edison Electric Institute
EIS	Energy Independence Strategy
EITF	Emerging Issues Task Force
EITF 06-11	EITF 06-11, "Accounting for Income Tax Benefits of Dividends or Share-based Payment Awards"
EMP	Energy Master Plan
EPA	United States Environmental Protection Agency
EPACT	Energy Policy Act of 2005
ESOP	Employee Stock Ownership Plan
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN	FASB Interpretation
FIN 39-1	FIN 39-1, "Amendment of FASB Interpretation No. 39"
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"
FMB	First Mortgage Bonds
FSP	FASB Staff Position
FSP SFAS 115-1 and SFAS 124-1	FSP SFAS 115-1 and SFAS 124-1, "The Meaning of Other-Than-Temporary Impairment and its Application to Certain Investments"
FTR	Financial Transmission Rights
GAAP	Accounting Principles Generally Accepted in the United States
GHG	Greenhouse Gases
HVAC	Heating, Ventilation and Air-conditioning
IRS	Internal Revenue Service
ISO	Independent System Operator
kv	Kilovolt
KWH	Kilowatt-hours
LOC	Letter of Credit
LTIP	Long-term Incentive Program
MEIUG	Met-Ed Industrial Users Group
MISO	Midwest Independent Transmission System Operator, Inc.
Moody's	Moody's Investors Service, Inc.
MOU	Memorandum of Understanding
MSG	Market Support Generation
MTC	Market Transition Charge
MW	Megawatts
MWH	Megawatt-hour
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NJBPU	New Jersey Board of Public Utilities
NOPR	Notice of Proposed Rulemaking
NOV	Notice of Violation
NO_x	Nitrogen Oxide
NRC	Nuclear Regulatory Commission
NSR	New Source Review
NUG	Non-Utility Generation
NUGC	Non-Utility Generation Charge
OAQDA	Ohio Air Quality Development Authority
OCA	Office of Consumer Advocate
OCC	Office of the Ohio Consumers' Counsel
OCI	Other Comprehensive Income
OPEB	Other Post-Employment Benefits
OVEC	Ohio Valley Electric Corporation

GLOSSARY OF TERMS Cont'd.

OWDA	Ohio Water Development Authority
PCRB	Pollution Control Revenue Bond
PICA	Penelec Industrial Customer Alliance
PJM	PJM Interconnection L. L. C.
PLR	Provider of Last Resort; an electric utility's obligation to provide generation service to customers whose alternative supplier fails to deliver service
PPUC	Pennsylvania Public Utility Commission
PRP	Potentially Responsible Party
PSA	Power Supply Agreement
PUCO	Public Utilities Commission of Ohio
PUHCA	Public Utility Holding Company Act of 1935
RCP	Rate Certainty Plan
REC	Renewable Energy Certificate
RECB	Regional Expansion Criteria and Benefits
RFP	Request for Proposal
ROP	Reactor Oversight Process
RSP	Rate Stabilization Plan
RTC	Regulatory Transition Charge
RTO	Regional Transmission Organization
RTOR	Regional Through and Out Rates
S&P	Standard & Poor's Ratings Service
S&P 500	Standard & Poor's Index of Widely Held Common Stocks
SBC	Societal Benefits Charge
SCR	Selective Catalytic Reduction
SEC	U.S. Securities and Exchange Commission
SECA	Seams Elimination Cost Adjustment
SERP	Supplemental Executive Retirement Plan
SFAS	Statement of Financial Accounting Standards
SFAS 13	SFAS No. 13, "Accounting for Leases"
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, "Disclosure about Fair Value of Financial Instruments"
SFAS 109	SFAS No. 109, "Accounting for Income Taxes"
SFAS 115	SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities"
SFAS 123(R)	SFAS No. 123(R), "Share-Based Payment"
SFAS 133	SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities"
SFAS 141(R)	SFAS No. 141(R), "Business Combinations"
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"
SFAS 160	SFAS No. 160, "Non-controlling Interests in Consolidated Financial Statements – an Amendment of ARB No. 51"
SIP	State Implementation Plan(s) Under the Clean Air Act
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
SRM	Special Reliability Master
TBC	Transition Bond Charge
TEBSA	Termobarranquila S.A. Empresa de Servicios Publicos
TMI-1	Three Mile Island Unit 1
TMI-2	Three Mile Island Unit 2
VIE	Variable Interest Entity

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 Financial Condition and Results of Operations" 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.

FIRSTENERGY CORP.

SELECTED FINANCIAL DATA

For the Years Ended December 31,	2007	2006	2005	2004	2003
		(In millions, except per share amounts)			
Revenues	$ 12,802	$ 11,501	$ 11,358	$ 11,600	$ 10,802
Income From Continuing Operations	$ 1,309	$ 1,258	$ 879	$ 907	$ 494
Net Income	$ 1,309	$ 1,254	$ 861	$ 878	$ 423
Basic Earnings per Share of Common Stock:					
Income from continuing operations	$ 4.27	$ 3.85	$ 2.68	$ 2.77	$ 1.63
Net earnings per basic share	$ 4.27	$ 3.84	$ 2.62	$ 2.68	$ 1.39
Diluted Earnings per Share of Common Stock:					
Income from continuing operations	$ 4.22	$ 3.82	$ 2.67	$ 2.76	$ 1.62
Net earnings per diluted share	$ 4.22	$ 3.81	$ 2.61	$ 2.67	$ 1.39
Dividends Declared per Share of Common Stock (1)	$ 2.05	$ 1.85	$ 1.705	$ 1.9125	$ 1.50
Total Assets	$ 32,068	$ 31,196	$ 31,841	$ 31,035	$ 32,878
Capitalization as of December 31:					
Common Stockholders' Equity	$ 8,977	$ 9,035	$ 9,188	$ 8,590	$ 8,290
Preferred Stock	-	-	184	335	335
Long-Term Debt and Other Long-Term Obligations	8,869	8,535	8,155	10,013	9,789
Total Capitalization	$ 17,846	$ 17,570	$ 17,527	$ 18,938	$ 18,414
Weighted Average Number of Basic Shares Outstanding	306	324	328	327	304
Weighted Average Number of Diluted Shares Outstanding	310	327	330	329	305

(1) Dividends declared in 2007 include three quarterly payments of $0.50 per share in 2007 and one quarterly payment of $0.55 per share payable in 2008, increasing the indicated annual dividend rate from $2.00 to $2.20 per share. Dividends declared in 2006 include three quarterly payments of $0.45 per share in 2006 and one quarterly payment of $0.50 per share paid in 2007. Dividends declared in 2005 include two quarterly payments of $0.4125 per share in 2005, one quarterly payment of $0.43 per share in 2005 and one quarterly payment of $0.45 per share in 2006. Dividends declared in 2004 include four quarterly dividends of $0.375 per share paid in 2004 and a quarterly dividend of $0.4125 per share paid in 2005. Dividends declared in 2003 include four quarterly dividends of $0.375 per share.

PRICE RANGE OF COMMON STOCK

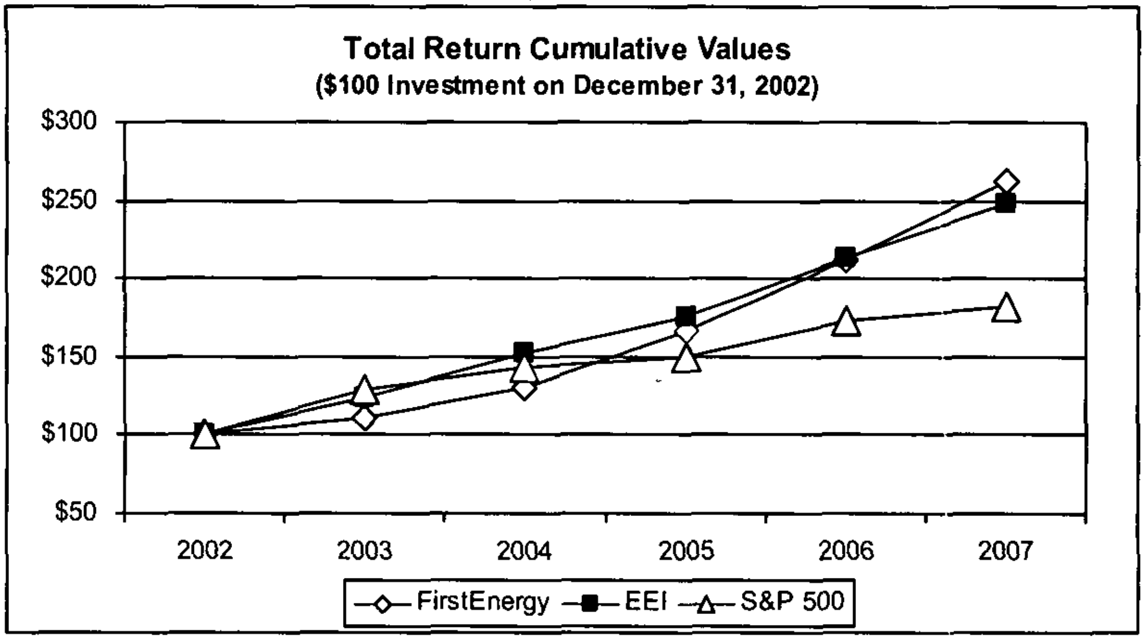
The common stock of FirstEnergy Corp. is listed on the New York Stock Exchange under the symbol "FE" and is traded on other registered exchanges.

	2007		2006	
First Quarter High-Low	$ 67.11	$ 57.77	$ 52.17	$ 47.75
Second Quarter High-Low	$ 72.90	$ 62.56	$ 54.57	$ 48.23
Third Quarter High-Low	$ 68.31	$ 58.75	$ 57.50	$ 53.47
Fourth Quarter High-Low	$ 74.98	$ 63.39	$ 61.70	$ 55.99
Yearly High-Low	$ 74.98	$ 57.77	$ 61.70	$ 47.75

Prices are from http://finance.yahoo.com.

SHAREHOLDER RETURN

The following graph shows the total cumulative return from a $100 investment on December 31, 2002 in FirstEnergy's common stock compared with the total cumulative returns of EEI's Index of Investor-Owned Electric Utility Companies and the S&P 500.



HOLDERS OF COMMON STOCK

There were 120,100 and 119,627 holders of 304,835,407 shares of FirstEnergy's common stock as of December 31, 2007 and January 31, 2008, respectively. Information regarding retained earnings available for payment of cash dividends is given in Note 11(A) to the consolidated financial statements.

CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

FIRSTENERGY CORP.

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

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 include declarations regarding our management's intents, beliefs and current expectations. These statements typically contain, but are not limited to, the terms "anticipate," "potential," "expect," "believe," "estimate" and similar words. Forward-looking statements involve estimates, assumptions, known and unknown risks, uncertainties and other factors that may cause actual results, performance or achievements to be materially different from any future results, performance or achievement expressed or implied by such forward-looking statements. Actual results may differ materially due to the speed and nature of increased competition in the electric utility industry and legislative and regulatory changes affecting how generation rates will be determined following the expiration of existing rate plans in Ohio and Pennsylvania, 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 of our regulated utilities to collect transition and other charges or to recover increased transmission costs, maintenance costs being higher than anticipated, other legislative and regulatory changes, revised environmental requirements, including possible GHG emission regulations, the uncertainty of the timing and amounts of the capital expenditures needed to, among other things, implement the Air Quality Compliance Plan (including that such amounts could be higher than anticipated) or levels of emission reductions related to the Consent Decree resolving the New Source Review litigation or other potential regulatory initiatives, adverse regulatory or legal decisions and outcomes (including, but not limited to, the revocation of necessary licenses or operating permits and oversight) by the NRC (including, but not limited to, the Demand for Information issued to FENOC on May 14, 2007) as disclosed in our SEC filings, the timing and outcome of various proceedings before the PUCO (including, but not limited to, the distribution rate cases and the generation supply plan filing for the Ohio Companies and the successful resolution of the issues remanded to the PUCO by the Ohio Supreme Court regarding the RSP and RCP, including the deferral of fuel costs) and the PPUC (including the resolution of the Petitions for Review filed with the Commonwealth Court of Pennsylvania with respect to the transition rate plan for Met-Ed and Penelec), the continuing availability of our generating units and their ability to operate at, or near full capacity, the changing market conditions that could affect the value of assets held in our nuclear decommissioning trusts, pension trusts and other trust funds, the ability to comply with applicable state and federal reliability standards, the ability to accomplish or realize anticipated benefits from strategic goals (including employee workforce initiatives), 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 risks and other factors discussed from time to time in our SEC filings, and other similar factors. The foregoing review of factors should not be construed as exhaustive. New factors emerge from time to time, and it is not possible to predict all such factors, nor assess the impact of any such factor on our business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statements. Also, a security rating is not a recommendation to buy, sell or hold securities, and it may be subject to revision or withdrawal at any time and each such rating should be evaluated independently of any other rating. We expressly disclaim any current intention to update any forward-looking statements contained herein as a result of new information, future events, or otherwise.*

EXECUTIVE SUMMARY

Net income in 2007 was $1.31 billion, or basic earnings of $4.27 per share of common stock ($4.22 diluted), compared with net income of $1.25 billion, or basic earnings of $3.84 per share ($3.81 diluted) in 2006 and $861 million, or basic earnings of $2.62 per share ($2.61 diluted) in 2005. The increase in our 2007 earnings was driven primarily by increased electric sales revenues, partially offset by increased purchased power costs, increased other operating expenses and higher amortization of regulatory assets.

Change in Basic Earnings Per Share From Prior Year	2007	2006	2005
Basic Earnings Per Share – Prior Year	$ 3.84	$ 2.62	$ 2.68
Non-core asset sales – 2007	0.04	-	-
Saxton decommissioning regulatory asset – 2007	0.05	-	-
Trust securities impairment – 2007/2006	(0.03)	(0.02)	-
PPUC NUG accounting adjustment – 2006	0.02	(0.02)	-
Ohio/New Jersey income tax adjustments – 2005	-	0.19	(0.19)
Sammis Plant New Source Review settlement – 2005	-	0.04	(0.04)
Davis-Besse fine/penalty – 2005	-	0.10	(0.10)
JCP&L arbitration decision – 2005	-	0.03	(0.03)
New regulatory assets - JCP&L settlement – 2005	-	(0.05)	0.05
Lawsuits settlements – 2004	-	-	0.03
Nuclear operations severance costs – 2004	-	-	0.01
Davis-Besse extended outage impacts – 2004	-	-	0.12
Discontinued Operations:			
Non-core asset sales/impairments	-	(0.02)	0.21
Other	0.01	(0.02)	(0.09)
Cumulative effect of a change in accounting principle	-	0.09	(0.09)
Revenues	2.51	0.26	(0.44)
Fuel and purchased power	(1.51)	(0.43)	0.72
Amortization of regulatory assets	(0.31)	0.78	(0.21)
Deferral of new regulatory assets	-	0.23	0.22
Other expenses	(0.43)	0.25	(0.27)
Investment income	(0.03)	(0.11)	0.02
Interest expense	(0.11)	(0.11)	0.02
Reduced common shares outstanding	0.22	0.03	-
Basic Earnings Per Share	$ 4.27	$ 3.84	$ 2.62

Total electric generation sales increased 2.5% during 2007 compared to the prior year, with retail and wholesale sales increasing 2.0%, and 4.5%, respectively. Electric distribution deliveries increased 2.6% in 2007 compared to 2006, reflecting load growth and higher weather-related usage in 2007.

Financial Matters

Dividends

On December 18, 2007, our Board of Directors declared a quarterly dividend of $0.55 per share on outstanding common stock, a 10% increase, payable on March 1, 2008. The new indicated annual dividend is $2.20 per share. This action brings our cumulative dividend increase to 47% since the beginning of 2005 and is consistent with our policy of sustainable annual dividend growth with a payout that is appropriate for our level of earnings.

Share Repurchase Programs

On March 2, 2007, we repurchased approximately 14.4 million shares, or 4.5%, of our outstanding common stock under an accelerated share repurchase program at an initial purchase price of approximately $900 million, or $62.63 per share. We paid a final purchase price adjustment in cash on December 13, 2007, resulting in a final purchase price of $942 million, or $65.54 per share.

On August 10, 2006, we repurchased approximately 10.6 million shares, or 3.2%, of our outstanding common stock through an accelerated share repurchase program. The initial purchase price was $600 million, or $56.44 per share. We paid a final purchase price adjustment of $27 million in cash on April 2, 2007. Under the two programs, we have repurchased approximately 25 million shares, or 8%, of the total common shares that were outstanding in July 2006.

Sale and Leaseback Transaction

On July 13, 2007, FGCO completed a $1.3 billion sale and leaseback transaction for its 779 MW interest in Unit 1 of the Bruce Mansfield Plant. The terms of the agreement provide for an approximate 33-year lease of Unit 1. We used the net, after-tax proceeds of approximately $1.2 billion to repay short-term debt that was used to fund the approximately $900 million share repurchase program and $300 million pension contribution. FES' registration obligations under the registration rights agreement applicable to the transaction were satisfied in September 2007, at which time the transaction was classified as an operating lease under GAAP for FES and us. The $1.1 billion book gain from the transaction was deferred and will be amortized ratably over the lease term. FGCO continues to operate the plant under the terms of the lease agreement and is entitled to the plant's output.

Credit Rating Agency Action

On March 26, 2007, S&P assigned its corporate credit rating of BBB to FES and on March 27, 2007, Moody's issued a rating of Baa2 to FES. FES is the holding company of FGCO and NGC, the owners of our fossil and nuclear generation assets, respectively. Both S&P and Moody's cited the strength of our generation portfolio as a key contributor to the investment grade credit ratings.

On October 18, 2007, S&P revised their outlook for us and our subsidiaries to negative from stable, citing the exposure of our generating assets in Ohio and Pennsylvania to market commodity risk.

On November 2, 2007, Moody's revised their outlook for us and our subsidiaries to stable from positive, citing a downward trend in financial metrics, our near-term capital expenditure program and increased regulatory uncertainty.

Extension and Amendment of Credit Facility

On November 20, 2007, we and certain of our subsidiaries, agreed, pursuant to a Consent and Amendment with the lenders under our $2.75 billion credit facility dated as of August 24, 2006, to extend the termination date of the facility for one year to August 24, 2012. We also agreed to amendments that will permit us to request an unlimited number of additional one-year extensions of the facility termination date upon shorter notice than provided by the original facility terms, which permitted only two such extensions. In addition, the amendments increase FES' borrowing sub-limit under the credit facility to up to $1 billion and remove any requirements for the delivery of a parental guaranty of FES' obligations.

New Financings

On March 27, 2007, CEI issued $250 million of 5.70% unsecured senior notes due 2017. The proceeds from the transaction were used to repay short-term borrowings and for general corporate purposes.

On May 21, 2007, JCP&L issued $550 million of senior unsecured debt securities. The offering was in two tranches, consisting of $250 million of 5.65% senior notes due 2017 and $300 million of 6.15% senior notes due 2037. The proceeds from the transaction were used to redeem all of JCP&L's outstanding FMBs, repay short-term debt and repurchase JCP&L's common stock from FirstEnergy.

On August 30, 2007, Penelec issued $300 million of 6.05% unsecured senior notes due 2017. A portion of the net proceeds from the issuance and sale of the senior notes was used to fund the repurchase of $200 million of Penelec's common stock from FirstEnergy. The remainder was used to repay short-term borrowings and for general corporate purposes.

On October 4, 2007, FGCO and NGC closed on the issuance of $427 million of PCRBs. Proceeds from the issuance were used to redeem an equal amount of outstanding PCRBs originally issued on behalf of the Ohio Companies. This transaction brings the total amount of PCRBs transferred from the Ohio Companies and Penn to FGCO and NGC to approximately $1.9 billion, with approximately $265 million remaining to be transferred. The transfer of these PCRBs supports the intra-system generation asset transfer that was completed in 2005.

Regulatory Matters - Ohio

Legislative Process

On September 25, 2007, the Ohio Governor's proposed energy plan was officially introduced into the Ohio Senate as Senate Bill 221. The bill proposed to revise state energy policy to address electric generation pricing after 2008, establish advanced energy portfolio standards and energy efficiency standards, and create GHG emission reporting and carbon control planning requirements. The bill also proposed to move to a "hybrid" system for determining generation rates for default service in which electric utilities would provide regulated generation service unless they satisfy a statutory burden to demonstrate the existence of a competitive market for retail electricity.

The Senate Energy & Public Utilities Committee conducted hearings on the bill and received testimony from interested parties, including the Governor's Energy Advisor, the Chairman of the PUCO, consumer groups, utility executives and others. On October 4, 2007, we provided testimony to the Committee citing several concerns with the introduced version of the bill, including its lack of context in which to establish prices. We recommended that the PUCO be provided the clear statutory authority to negotiate rate plans, and in the event that negotiations do not result in rate plan agreements, a competitive bidding process be utilized to establish generation prices for customers that do not choose alternative suppliers. We also proposed that the PUCO's statutory authority be expanded to promote societal programs such as energy efficiency, demand response, renewable power, and infrastructure improvements. Several proposed amendments to the bill were submitted, including those from Ohio's investor-owned electric utilities. On October 25, 2007, a substitute version of the bill, which incorporated certain of the proposed amendments, was introduced into the Senate Energy & Public Utilities Committee. On October 31, 2007, the Ohio Senate passed Substitute Senate Bill 221. Among other things, the bill outlines a process for establishing electricity generation prices beginning in 2009, and includes a requirement that at least 25% of the state's electricity come from advanced energy technologies by 2025, with at least one-half of that amount coming from renewable resources.

In November 2007, the Ohio House of Representatives referred the bill to the House Public Utilities Committee, which has since conducted various topic-based hearings on the bill. Testimony has been received from interested parties, including the Chairman of the PUCO, consumer groups, utility executives and others. On November 14, 2007, we provided testimony on the history and status of deregulation in Ohio. We said that Ohioans should have the opportunity to participate in the competitive electricity marketplace as provided for under Ohio's 1999 deregulation law, Senate Bill 3, which set the stage for long-term price moderation as well as more reliable and responsive service for Ohio's customers. On November 28, 2007, we provided further testimony expressing the industry's concerns with Substitute Senate Bill 221. We said the legislation should be modified to provide the PUCO with expanded regulatory tools and statutory authority to negotiate rate plans, and to include a true market rate option. At this time, we cannot predict the outcome of this process nor determine the impact, if any, such legislation may have on our operations.

Distribution Rate Request

On June 7, 2007, the Ohio Companies filed their base distribution rate increase request and supporting testimony with the PUCO. The requested increase of approximately $332 million in annualized distribution revenues (updated on August 6, 2007) is needed to recover expenses related to distribution operations and the costs deferred under previously approved rate plans. The new rates would become effective with the first billing cycle in January 2009 for OE and TE, and approximately May 2009 for CEI. Concurrent with the effective dates of the proposed distribution rate increases, the Ohio Companies will reduce or eliminate their RTC revenues, resulting in an estimated net reduction of $262 million on the regulated portion of customers' bills.

On December 4, 2007, the PUCO Staff issued its Staff Reports containing the results of their investigation into the distribution rate request. In its reports, the PUCO Staff recommended a distribution rate increase in the range of $161 million to $180 million, compared to the Ohio Companies' request of $332 million. On January 3, 2008, the Ohio Companies and intervening parties filed objections to the Staff Reports and on January 10, 2008, the Ohio Companies filed supplemental testimony. Evidentiary hearings were commenced on January 29, 2008 and continued through February 2008. During the evidentiary hearings, the PUCO Staff submitted testimony decreasing their recommended revenue increase to a range of $114 million to $132 million. The PUCO is expected to render its decision during the second or third quarter of 2008.

Generation Supply Proposal

On July 10, 2007, the Ohio Companies filed an application with the PUCO requesting approval of a comprehensive supply plan for providing generation service to customers who do not purchase electricity from an alternative supplier, beginning January 1, 2009. The proposed competitive bidding process would average the results of multiple bidding sessions conducted at different times during the year. The final price per kilowatt-hour included in rates would reflect an average of the prices resulting from all successful bid sessions. In their filing, the Ohio Companies offered two alternatives for structuring the bids, either by customer class or a "slice-of-system" approach. A slice-of-system approach would require the successful bidder to be responsible for supplying a fixed percentage of the utility's total load notwithstanding the customer's classification. The proposal also provides the PUCO with the option to phase in generation price increases for any residential tariff group if the outcome of a bid would otherwise result in an increase in average total price of 15% or more. On August 16, 2007, the PUCO held a technical conference for interested parties to gain a better understanding of the proposal. Initial and reply comments on the proposal were filed by various parties in September and October, 2007, respectively. The proposal is currently pending before the PUCO.

RCP Fuel Remand

On August 29, 2007, the Supreme Court of Ohio upheld findings by the PUCO, approving several provisions of the Ohio Companies' RCP. The Court, however, remanded back to the PUCO for further consideration the portion of the PUCO's RCP order that authorized the Ohio Companies to collect deferred fuel costs through future distribution rates. The Court found recovery of competitive generation service costs through noncompetitive distribution rates unlawful. The PUCO's order had authorized the Ohio Companies to defer increased fuel costs incurred from January 1, 2006 through December 31, 2008, including interest on the deferred balances, and to recover these deferred costs over a 25-year period beginning in 2009. On September 7, 2007, the Ohio Companies filed a Motion for Reconsideration with the Court on the issue of the deferred fuel costs, which the Court later denied on November 21, 2007. On September 10, 2007, the Ohio Companies filed an Application on remand with the PUCO proposing that the increased fuel costs be recovered through two generation-related fuel cost recovery riders during the period of October 2007 through December 2008. On January 9, 2008 the PUCO approved the Ohio Companies' proposed fuel cost rider to recover fuel costs incurred from January 1, 2008 through December 31, 2008, which is expected to be approximately $167 million. The fuel cost rider was effective January 11, 2008 and will be adjusted and reconciled quarterly. In addition, the PUCO ordered the Ohio Companies to file a separate application for an alternate recovery mechanism to collect the 2006 and 2007 deferred fuel costs. On February 8, 2008, the Ohio Companies filed an application proposing to recover $220 million of deferred fuel costs and carrying charges for 2006 and 2007 pursuant to a separate fuel rider, with alternative options for the recovery period ranging from 5 to 25 years. This second application is pending before the PUCO.

Renewable Energy Option

On August 15, 2007, the PUCO approved a stipulation filed by the Ohio Companies, PUCO Staff and the OCC that creates a green pricing option for customers of the Ohio Companies. The Green Resource Program enables customers to support the development of alternative energy resources through their voluntary participation in this alternative to the Ohio Companies' standard service offer for generation supply. The Green Resource Program provides for the Ohio Companies to purchase RECs at prices determined through a competitive bidding process monitored by the PUCO.

Regulatory Matters – Pennsylvania

Legislative Process

On February 1, 2007, the Governor of Pennsylvania proposed an EIS. The EIS includes four pieces of proposed legislation that, according to the Governor, are designed to reduce energy costs, promote energy independence and stimulate the economy. Elements of the EIS include the installation of smart meters, funding for solar panels on residences and small businesses, conservation and demand reduction programs to meet energy growth, a requirement that electric distribution companies acquire power that results in the "lowest reasonable rate on a long-term basis," the utilization of micro-grids and a three year phase-in of rate increases.

On July 17, 2007 the Governor signed into law two pieces of energy legislation. The first amended the Alternative Energy Portfolio Standards Act of 2004 to, among other things, increase the percentage of solar energy that must be supplied at the conclusion of an electric distribution company's transition period. The second law allows electric distribution companies, at their sole discretion, to enter into long-term contracts with large customers and to build or acquire interests in electric generation facilities specifically to supply long-term contracts with such customers. A special legislative session on energy was convened in mid-September 2007 to consider other aspects of the EIS. The final form of any legislation arising from the special legislative session is uncertain. Consequently, we are unable to predict what impact, if any, such legislation may have on our operations.

Penn's Interim Default Service Supply

On May 2, 2007, Penn made a filing with the PPUC proposing how it will procure the power supply needed for default service customers beginning June 1, 2008. Penn's customers transitioned to a fully competitive market on January 1, 2007, and the default service plan that the PPUC previously approved covered a 17-month period through May 31, 2008. The filing proposed that Penn procure a full-requirements product, by customer class, through multiple RFPs with staggered delivery periods extending through May 2011. It also proposed a 3-year phase-out of promotional generation rates.

On September 28, 2007, Penn filed a Joint Petition for Settlement resolving all but one issue in the case. Briefs were also filed on September 28, 2007 on the unresolved issue of incremental uncollectible accounts expense. The settlement was either supported, or not opposed, by all parties. On December 20, 2007, the PPUC approved the settlement except for the full requirements tranche approach for residential customers, which was remanded to the ALJ for further proceedings. Under the terms of the Settlement Agreement, the default service procurement for small commercial customers will be done with multiple RFPs, while the default service procurement for large commercial and industrial customers will utilize hourly pricing. Bids in the first RFP for small commercial load were received on February 20, 2008. In February 2008, parties filed direct and rebuttal testimony in the remand proceeding for the residential procurement approach. An evidentiary hearing was held on February 26, 2008, and this matter is expected to be presented to the PPUC for its consideration by March 13, 2008.

Commonwealth Court Appeal

On January 11, 2007, the PPUC issued its order in the Met-Ed and Penelec 2006 comprehensive transition rate cases (see Note 10(C)). Met-Ed and Penelec subsequently appealed the PPUC's decision on the denial of generation rate relief and on a consolidated income tax adjustment related to the cost of capital to the Pennsylvania Commonwealth Court, while other parties appealed the PPUC's decision on transmission rate relief to that court. Initial briefs in the appeals were filed on June 19, 2007. Responsive briefs and reply briefs were filed on September 21, 2007 and October 5, 2007, respectively. Oral arguments are expected to take place in early 2008.

Generation

Our generating fleet produced 81.0 billion KWH during 2007 compared to 82.0 billion KWH in 2006. Our nuclear fleet produced a record 30.3 billion KWH, while the non-nuclear fleet produced 50.7 billion KWH.

During 2007, generation capacity at several of our units increased as a result of work completed in connection with outages for refueling or other maintenance. These capacity additions were achieved in support of our operating strategy to maximize existing generation assets. The resulting increases in the net demonstrated capacity of our generating units are summarized below:

2007 Power Uprates (MW)	
Fossil:	
Bruce Mansfield Unit 3	30
Seneca Unit 2	8
	38
Nuclear:	
Beaver Valley Unit 1	43
Beaver Valley Unit 2	24
	67
Total	105

Our supply portfolio was also enhanced during the year through the reduction of seasonal derates by 149 MW at our peaking units and through long-term contracts to purchase the output of 115 MW from wind generators.

Complementing our strategy of incremental enhancements to our current generating fleet, FGCO identified an opportunity to acquire a partially completed 707-MW natural gas fired generating plant in Fremont, Ohio. On January 28, 2008, FGCO entered into definitive agreements with Calpine Corporation to acquire the plant for $253.6 million, following a competitive bid process. The facility includes two combined-cycle combustion turbines and a steam turbine which are expected to be capable of producing approximately 544 MW of load-following capacity and 163 MW of peaking capacity. In court documents, Calpine has estimated that the plant is 70% complete and could become operational within 12 to 18 months. Based on those documents, FGCO estimates that the additional expenditures to complete the facility to be approximately $150 million to $200 million. The final cost and timeframe for construction are subject to FGCO's pending engineering study.

Environmental Update

In February 2007, a SNCR system was placed in-service at Unit 5 of FGCO's Eastlake Plant, upon completion of a scheduled maintenance outage. The SNCR installation is part of our overall Air Quality Compliance Strategy and was required under the NSR Consent Decree. The SNCR system is expected to reduce NOx emissions and help achieve reductions required by the EPA's NOx Transport Rule.

On May 30, 2007, we announced that FGCO plans to install an ECO system on Units 4 and 5 of the R.E. Burger Plant. Design engineering for the new Burger Plant ECO system began in 2007 with anticipated start-up in the first quarter of 2011.

Perry Nuclear Power Plant

On March 2, 2007, the NRC returned the Perry Plant to routine agency oversight as a result of its assessment of the corrective actions that FENOC has taken over the last two-and-one-half years. The plant had been operating under heightened NRC oversight since August 2004. On May 8, 2007, as a result of a "white" Emergency AC Power Systems mitigating systems performance indicator, the NRC notified FENOC that the Perry Plant was being placed in the Regulatory Response Column (Column 2 of the ROP) and additional inspections would be conducted.

On June 29, 2007, the Perry Plant began an unplanned outage to replace a 30-ton motor in the reactor recirculation system. In addition to the motor replacement, routine and preventive maintenance and several system inspections were performed during the outage to assure continued safe and reliable operation of the plant. On July 25, 2007, the plant was returned to service.

On August 21, 2007, FENOC announced plans to expand used nuclear fuel storage capacity at the Perry Plant. The plan calls for installing above-ground, airtight steel and concrete cylindrical canisters, cooled by natural air circulation, to store used fuel assemblies. Construction of the new fuel storage system, which is expected to cost approximately $30 million, is scheduled to begin in the spring of 2008, with completion planned for 2010.

Beaver Valley Power Station

On October 24, 2007, Beaver Valley Unit 1 returned to service following completion of its scheduled refueling outage that began on September 24, 2007. During the outage, the ten-year in-service inspection of the reactor vessel was also completed with no significant issues identified. Beaver Valley Unit 1 had operated for 378 consecutive days when it was taken off line for the outage.

In August 2007, FENOC filed applications with the NRC seeking renewal of the operating licenses for Beaver Valley Units 1 and 2 for an additional 20 years, which would extend the operating licenses to January 29, 2036, for Unit 1 and May 27, 2047, for Unit 2. On November 9, 2007, FENOC announced that the NRC's preliminary requirements to extend the licenses had been met. The NRC held a public meeting on November 27, 2007 to discuss the license renewal. Over the next two years, the NRC will conduct audits and an environmental survey. A decision on the applications is expected in the third quarter of 2009.

Davis-Besse Nuclear Power Station

On May 14, 2007, the NRC issued a Demand for Information to FENOC regarding two reports prepared by expert witnesses for an insurance arbitration related to Davis-Besse. On June 13, 2007, FENOC filed a response to the NRC's Demand for Information reaffirming that it accepts full responsibility for the mistakes and omissions leading up to the damage to the reactor vessel head and that it remains committed to operating Davis-Besse and our other nuclear plants safely and responsibly. In follow-up discussions, FENOC was asked to provide supplemental information to clarify certain aspects of the Demand for Information response and provide additional details regarding plans to implement the commitments made therein. FENOC submitted this supplemental response to the NRC on July 16, 2007. On August 15, 2007, the NRC issued a confirmatory order imposing these commitments. FENOC must inform the NRC's Office of Enforcement after it completes the key commitments embodied in the NRC's order. FENOC's compliance with these commitments is subject to future NRC review.

On February 14, 2008, Davis-Besse returned to service following completion of its scheduled refueling outage, which began on December 30, 2007. In addition to replacing 76 of the 177 fuel assemblies, several improvement projects were completed, including rewinding the turbine generator and reinforcing welds on plant equipment.

FIRSTENERGY'S BUSINESS

We are a diversified energy company headquartered in Akron, Ohio, that operates primarily through three core business segments (see "Results of Operations").

- **Energy Delivery Services** transmits and distributes electricity through our eight utility operating companies, serving 4.5 million customers within 36,100 square miles of Ohio, Pennsylvania and New Jersey and purchases power for its PLR and default service requirements in Pennsylvania and New Jersey. This business segment derives its revenues principally from the delivery of electricity within our service areas, cost recovery of regulatory assets and the sale of electric generation service to retail customers who have not selected an alternative supplier (default service) in its Pennsylvania and New Jersey franchise areas. Its net income reflects the commodity costs of securing electricity from our competitive energy services segment under partial requirements purchased power agreements with FES and from non-affiliated power suppliers, including, in each case, associated transmission costs.

  The service areas of our utilities are summarized below:

Company	Area Served	Customers Served
OE	Central and Northeastern Ohio	1,040,000
Penn	Western Pennsylvania	159,000
CEI	Northeastern Ohio	756,000
TE	Northwestern Ohio	313,000
JCP&L	Northern, Western and East Central New Jersey	1,087,000
Met-Ed	Eastern Pennsylvania	546,000
Penelec	Western Pennsylvania	589,000
ATSI	Service areas of OE, Penn, CEI and TE	

- **Competitive Energy Services** supplies the electric power needs of end-use customers through retail and wholesale arrangements, including associated company power sales to meet all or a portion of the PLR and default service requirements of our Ohio and Pennsylvania utility subsidiaries and competitive retail sales to customers primarily in Ohio, Pennsylvania, Maryland and Michigan. This business segment owns or leases and operates 19 generating facilities with a net demonstrated capacity of approximately 13,664 MWs and also purchases electricity to meet sales obligations. The segment's net income is primarily derived from affiliated company power sales and non-affiliated electric generation sales revenues less the related costs of electricity generation, including purchased power and net transmission and ancillary costs charged by PJM and MISO to deliver energy to the segment's customers.

- **Ohio Transitional Generation Services** supplies the electric power needs of non-shopping customers under the default service requirements of our Ohio Companies. The segment's net income is primarily derived from electric generation sales revenues less the cost of power purchased from the competitive energy services segment through a full-requirements PSA arrangement with FES, including net transmission and ancillary costs charged by MISO to deliver energy to retail customers.

Other operating segments include HVAC services (divestiture completed in 2006) and telecommunication services. We have substantially completed the divestiture of our non-core businesses (see Note 8 to the consolidated financial statements). The assets and revenues for the other business operations are below the quantifiable threshold for separate disclosure as "reportable operating segments."

STRATEGY AND OUTLOOK

We have developed four primary objectives that support our business fundamentals including improving operating performance, strengthening financial results, enhancing shareholder value and ensuring a safe work environment. To achieve these goals, we have implemented strategies that are expected to enable us to maximize our performance by successfully managing the transition to competitive generation markets; investing in our transmission and distribution infrastructure to enhance system reliability and customer service; reinvesting in our generating assets for cost-effective growth and environmental improvement; effectively managing commodity supplies and risks; and delivering consistent and predictable financial results.

Transition to Competitive Generation Markets

2004 to 2006

From 2004 to 2006, our efforts included preparing for competitive generation markets by improving the operational performance of our generating fleet and the reliability of our transmission and distribution system. Key to preparing for market competition for generation was transferring ownership of our generating assets in 2005 from the Ohio Companies and Penn to subsidiaries of FES, our competitive generation subsidiary. With the previous divestiture of generation assets by JCP&L, Met-Ed and Penelec, and JCP&L's transition to competitive generation markets through the New Jersey BGS auction, we gained experience in producing and acquiring competitively priced electricity for customers while delivering a fair return to shareholders. We anticipate leveraging this experience when we transition to competitive generation markets in Ohio.

To facilitate a smooth transition to competitive generation markets, we developed and received PUCO approval of a Rate Stabilization Plan (RSP) that was implemented in August 2004. This plan, along with the Rate Certainty Plan (RCP) approved in January 2006, provided Ohio customers with reliable generation supply and price stability through 2008.

We focus our continuing transition to market generation prices in Ohio and Pennsylvania over three periods - 2007 to 2008, 2009 to 2010, and beyond.

2007 to 2008

Effective January 1, 2007, we successfully transitioned Penn to retail rates for generation service derived from a competitive, wholesale power supply procurement process in Pennsylvania. During the year we also completed comprehensive rate cases for Met-Ed and Penelec, which better aligned their distribution and transmission rates to their rate base and costs to serve customers. However, Met-Ed and Penelec were unsuccessful in securing approval for generation rate increases. As a result, FES expects to continue to provide both companies with partial requirements for their PLR and default service load of up to approximately 20 billion KWH at below-market prices through the end of 2010 when their current rate freeze ends. In Ohio, the first distribution rate cases in more than a decade were filed by our Ohio Companies in 2007. However, new rates are not expected to be implemented until 2009.

Our transition to competitive generation markets was supported by continuing strong operational results in 2007 led by generation output of 81 billion KWH. During the year, the net-demonstrated capacity at several of our units was increased by a total of 105 MW through cost-effective unit upgrades. We signed long-term contracts to purchase 115 MW of output from wind generators and made plant improvements that eliminated the impact of 149 MW of seasonal reductions in generating output caused by elevated summer temperature conditions on our peaking units. We also continued to improve transmission and distribution system reliability and customer service.

As we look ahead to 2008, we expect to continue our focus on operational excellence with an emphasis on continuous improvement in our core business to position for success in the next market transition phase. This includes continued investment in projects to increase our generation capacity and energy production capability as well as programs to continue to improve the reliability of our transmission and distribution systems. We also intend to remain actively engaged in shaping the regulatory landscape in Ohio and Pennsylvania, which is discussed in greater detail under "Legislative Outlook," "Capital Expenditures Outlook" and "Environmental Outlook" below.

With no expected rate increases to offset significantly higher Ohio transition cost amortization expense, coupled with higher depreciation expense and general taxes from increased investments in our energy delivery business and AQC projects as discussed more fully under "Environmental Outlook" below, we expect 2008 earnings growth to moderate compared to recent years. Expected drivers of 2008 earnings, both positive and negative, are discussed more fully below under "Financial Outlook."

2009 to 2010, and Beyond

Under current state law, the default service obligation for the Ohio Companies is scheduled to move to the competitive generation market on January 1, 2009. This is expected to provide our competitive energy services business with an opportunity to capture market-based retail generation rates for the incremental load (approximately 51 billion KWH in 2007) currently sold to the Ohio Companies under existing PSAs at below-market prices to cover default service obligations. We also expect to implement higher distribution rates for our three Ohio Companies in 2009 as a result of rate cases filed in 2007. Transition cost amortization related to the existing rate plans ends for OE and TE on December 31, 2008, and approximately May 2009 for CEI.

There are two primary factors in 2009 that we expect will adversely impact financial results for 2009 and 2010. The first is declining margins from the RSP and RCP. These plans helped us recover transition costs, but over time the benefit received from those plans will cease. The most significant impact will occur in 2009 when RTC revenues significantly decline and cost deferrals for infrastructure improvements end. These reductions are expected to be partially offset by a substantial decrease in transition cost amortization noted above.

The second factor is the scheduled termination - at the beginning of 2009 - of a favorably priced third-party supply contract serving Met-Ed and Penelec default service customers. Currently, we expect FES will supply an estimated additional 4.5 billion KWH from its supply portfolio under the existing contract with Met-Ed and Penelec. However, because retail generation rates for these two subsidiaries are frozen at a level below current market prices through the end of 2010, FES will incur the related opportunity cost in 2009 and 2010 since it will be unable to sell this power at the higher market prices.

Another major transition period in Pennsylvania will begin in 2011 as the current rate freeze on Met-Ed and Penelec's retail generation rates is expected to end. The companies expect to obtain their power supply from the competitive wholesale market and fully recover their costs through retail rates. Until then, we expect FES will provide approximately 20 billion KWH of below-market priced power to serve Met-Ed and Penelec's load in 2009 and 2010, including the load applicable to the expiring contract referred to above. Beginning in 2011, we expect to redeploy this power to capture the potential upside from market-based generation rates.

We will continue to be actively engaged in the regulatory process in Ohio and Pennsylvania as we strategically manage the transition to competitive generation markets. We also plan to continue our efforts to extract additional production capability from existing generating plants as discussed under "Capital Expenditures Outlook" below and carefully deploy our cash flow, striving for continuous improvement, while maintaining the strategic flexibility we will need as we move through these transitions.

Legislative Outlook

Efforts are underway by both the executive and legislative branches of government in Ohio and Pennsylvania to introduce new energy legislation. There are multiple issues being considered, including, but not limited to, how the transition to competitive generation markets will occur in each state. See "Regulatory Matters – Ohio" and "Regulatory Matters – Pennsylvania" above.

The major legislative effort in Ohio is centered on the Governor's proposed energy plan, which was officially introduced into the Ohio Senate as Senate Bill 221. The bill proposed to revise state energy policy to address electric generation pricing after 2008, establish advanced energy portfolio standards and energy efficiency standards, and create greenhouse gas emission reporting and carbon control planning requirements. The bill also proposed to move to a "hybrid" system for determining rates for default service in which electric utilities would provide regulated generation service unless they satisfy a statutory burden to demonstrate the existence of a competitive generation market for retail electricity.

We were among the interested parties who have provided testimony on the bill during hearings in both the Ohio Senate and the House.

The House Public Utilities Committee conducted topic-based hearings and public hearings between November 2007 and February 2008. The House Committee also received testimony on the bill's alternative options for establishing electric generation pricing in 2009. The electric utility industry's primary concern is that the current version of the bill does not offer a true hybrid approach because it does not provide the PUCO with adequate statutory authority to continue the success of rate plans or to offer customers the benefits of a competitive generation marketplace.

In Pennsylvania, a number of energy-related legislative proposals have been introduced, including plans to fund the Governor's proposed $850 million Energy Independence Fund. As proposed, the Fund would be created through a systems-benefit charge added to customers' bills that would support clean energy activities. Legislation was unveiled in February 2007, but failed to pass as part of the state budget. The Governor began a special energy session on September 24, 2007, announcing the identical proposal. On December 12, 2007, the Pennsylvania Senate passed SS SB1, "Alternative Energy Investment Act" which, as amended, would provide $650 million over 10 years in funding to implement the Governor's proposal. The bill was referred to the House Environmental Resources and Energy committee where it awaits consideration. Other legislation has been introduced to address generation procurement, expiration of rate caps, conservation, demand side management, smart meters and renewable energy.

Financial Outlook

Our primary financial focus is on:

- Delivering consistent financial results,
- Maintaining and building our financial strength and flexibility, and
- Using our cash flow to benefit investors and maintain or improve our investment-grade ratings.

Positive earnings drivers in 2008 are expected to include:

- Incremental growth in distribution sales due to more customers and approximately 1-2% higher electricity use from 2007 levels,
- Lower operation and maintenance expenses as a result of fewer scheduled outage days in our generating fleet compared to 2007,
- Lower financing costs compared to 2007 when short-term borrowing levels remained high for a significant portion of that year as a result of our interim financing of the approximately $900 million accelerated share repurchase program in March and a $300 million voluntary pension contribution in January. These borrowings were repaid with the proceeds from the $1.3 billion Bruce Mansfield Unit 1 sale and leaseback transaction. Without similar needs for short-term financing in 2008, we expect a decrease in borrowing costs.
- On a per share basis, a full year benefit from the reduced number of common shares outstanding resulting from the accelerated share repurchase program executed in March 2007, and
- Increased generation output. We expect to generate approximately 85 billion KWH in 2008 compared to 81 billion KWH in 2007 as we continue to focus on excellence in operational performance, including running the plants more efficiently and effectively.

Negative earnings drivers in 2008 are expected to include:

- Ohio transition cost amortization expense, a non-cash item, will be approximately $69 million higher under the amortization schedules in our current Ohio rate plans,
- Depreciation expenses and property taxes will be higher as we continue to invest capital in our business. These investments include our expenditures for distribution and reliability programs and for our AQC projects, and
- Fuel and purchase power expenses will continue to increase.

Net cash from operating activities in 2007 was $1.7 billion which includes a $300 million reduction for the voluntary pension contribution made in January. In 2008, we expect net cash from operations will increase to approximately $2.3 billion.

As we enter 2009, we expect to capture the potential upside from market-based generation rates in Ohio. Beginning at that time, we also should see a decline in AQC-related capital expenditure levels, providing an increase in free cash flow.

A driver for longer-term earnings growth is our effort to improve the utilization and output of our generation fleet. We are also expecting timely recovery of costs and capital investments in our regulated business. We plan to invest approximately $3.7 billion in our regulated energy delivery services business during the 2008-2012 period and to pursue timely recovery of those costs in rates. We also expect rising prices for fuel, purchased power and other operating costs to continue during this period.

Capital Expenditures Outlook

Our capital expenditures forecast for 2008-2012 is approximately $7.6 billion. Approximately $1.3 billion of this relates to AQC projects discussed under "Environmental Outlook" below. Annual expenditures for this program are expected to peak in 2008, increasing from $386 million in 2007 to $649 million in 2008. AQC expenditures are expected to decline in 2009 to approximately $500 million and by early 2012 we expect the program to be completed.

With respect to the remainder of our business, we anticipate average annual capital expenditures of approximately $1.2 billion from 2009 through 2012. Distribution and transmission reliability projects average approximately $730 million per year over the next five years. Expenditures for our competitive energy services business are expected to be higher than 2008 levels as a result of capital investments to further increase the output of our existing generating plants and to improve the availability and efficiency of those facilities in the future.

Compared to the construction of new base-load generation assets, we believe our strategy of making incremental additions and operational improvements to our generating fleet to improve output and reliability provides advantages including lower capital costs, reduced technology risk, decreased risk of project cost overruns and an accelerated time to market for the added output. In the near-term, we do not anticipate the need for additional base-load generation. However, we will continue to evaluate opportunities that complement our strategy, such as acquiring the partially completed natural gas fired generating plant in Fremont, Ohio, to enhance our fleet. See "Generation" above for more details on the Fremont plant.

Major capital investments planned at our nuclear plants during this time period include approximately $170 million for replacement of the steam generator at Davis-Besse. While this project is not expected to be completed until 2014, fabrication of some equipment is beginning. We also anticipate spending approximately $200 million for planned power uprates at Davis-Besse, Perry and Beaver Valley during this period. Combined, these expenditures represent approximately $370 million of increased capital over a typical maintenance level for nuclear generation during the 2008 to 2012 period.

Projected non-AQC capital spending for 2008 and, on average, for each of the years in the 2009 to 2012 period are:

Projected Non-AQC Capital Spending by Business Unit	**2008**	**2009-2012 Average**
	(In millions)	
Energy Delivery	$ 730	$ 730
Nuclear	132	259
Fossil	354	168
Corporate & Other	173	66
Subtotal without AQC	$ 1,389	$ 1,223

Projected capital expenditures for our AQC plan for each of the years 2008 through 2012, and the change in annual spending, are:

Projected AQC Capital Spending	**2008**	**2009**	**2010**	**2011**	**2012**
			(In millions)		
AQC	$ 649	$ 500	$ 156	$ 11	$ 4
Change from Prior Year	263	(149)	(344)	(145)	(7)

Environmental Outlook

With respect to compliance with environmental laws and regulations, we believe our generation fleet is well positioned due to substantial investment in pollution control equipment we have already made and will continue to make over the next few years pursuant to our AQC plan. The plan includes projects designed to ensure that all of the facilities in our generation fleet are operated in compliance with all applicable emissions standards and limits, including NO_x and SO_2. It also fulfills the requirements imposed by the 2005 consent decree that resolved the Sammis NSR litigation. See "Environmental Matters" below. By 2010, we expect approximately 80% of our generating fleet to have full NO_x and SO_2 equipment controls and to have decreased our exposure to the volatile emission allowance market.

The following table shows the percentage of our 2007 generating capacity made up of non-emitting and low-emitting generating units, including coal units retrofitted with best available control technology as well as projections for 2010.

	2007		**2010***	
Fleet Emission Control Status	**Capacity (MW)**	**Fleet %**	**Capacity (MW)**	**Fleet %**
Non-Emitting	4,581	34	4,638	34
Coal Controlled (SO_2/ NO_x-full control)	2,626	19	5,237	38
Natural Gas Peaking	1,283	9	1,283	9
	8,490	62	11,158	81

*Excludes Fremont

Momentum is building in the United States for some form of greenhouse gas regulation. See "Environmental Matters" below. We believe that our generation fleet is competitively positioned as we move toward a carbon-constrained world with about 35% of our generation output coming from non-emitting nuclear and hydro power.

While we have relatively low carbon intensity (i.e., CO_2 emitted per KWH) due primarily to our non-emitting nuclear fleet, our total CO_2 emissions will continue to increase as fossil plant utilization increases. We are involved in the following research and other activities, as part of our GHG compliance strategy:

- Pilot testing of CO_2 capture and sequestration technology,
- Electric Power Research Institute's Coal Fleet for Tomorrow,
- Nuclear uprates and license renewals to increase and maintain FES' non-emitting nuclear units; and
- Participation in the DOE's Midwest Regional Carbon Sequestration Partnership, New Jersey's Clean Energy Program, and the EPA's Sulfur Hexafluoride Reduction Partnership.

In addition, we will remain actively engaged in the federal and state debate over future environmental requirements and legislation, especially those dealing with potential global climate change. Due to the significant uncertainty as to the final form of any such legislation at both the federal and state levels, it is possible that we would be required to make additional capital expenditures, which could have a material adverse impact on our financial condition and results of operation.

Achieving Our Vision

Our success, in these and other key areas, will help us continue to achieve our vision of being a leading regional energy provider, recognized for operational excellence, outstanding customer service and our commitment to safety; the choice for long-term growth, investment value and financial strength; and a company driven by the leadership, skills, diversity and character of our employees.

RISKS AND CHALLENGES

In executing our strategy, we face a number of industry and enterprise risks and challenges, including:

- Risks arising from the reliability of our power plants and transmission and distribution equipment;
- Changes in commodity prices could adversely affect our profit margins;
- We are exposed to operational, price and credit risks associated with selling and marketing products in the power markets that we do not always completely hedge against;
- The use of derivative contracts by us to mitigate risks could result in financial losses that may negatively impact our financial results;
- Our risk management policies relating to energy and fuel prices, and counterparty credit are by their very nature risk related, and we could suffer economic losses despite such policies;
- Nuclear generation involves risks that include uncertainties relating to health and safety, additional capital costs, the adequacy of insurance coverage and nuclear plant decommissioning;
- Capital market performance and other changes may decrease the value of decommissioning trust fund, pension fund assets and other trust funds which then could require significant additional funding;
- We could be subject to higher costs and/or penalties related to mandatory NERC/FERC reliability standards;
- We rely on transmission and distribution assets that we do not own or control to deliver our wholesale electricity. If transmission is disrupted including our own transmission, or not operated efficiently, or if capacity is inadequate, our ability to sell and deliver power may be hindered;

- Disruptions in our fuel supplies could occur, which could adversely affect our ability to operate our generation facilities and impact financial results;
- Seasonal temperature variations, as well as weather conditions or other natural disasters could have a negative impact on our results of operations and demand significantly below or above our forecasts could adversely affect our energy margins;
- We are subject to financial performance risks related to the economic cycles of the electric utility industry;
- The goodwill of one or more of our operating subsidiaries may become impaired, which would result in write-offs of the impaired amounts;
- We face certain human resource risks associated with the availability of trained and qualified labor to meet our future staffing requirements;
- Significant increases in our operation and maintenance expenses, including our health care and pension costs, could adversely affect our future earnings and liquidity;
- Our business is subject to the risk that sensitive customer data may be compromised, which could result in an adverse impact to our reputation and/or results of operations;
- Acts of war or terrorism could negatively impact our business;
- Capital improvements and construction projects may not be completed within forecasted budget, schedule or scope parameters;
- We may acquire assets that could present unanticipated issues for our business in the future, which could adversely affect our ability to realize anticipated benefits of those acquisitions;
- Complex and changing government regulations could have a negative impact on our results of operations;
- Regulatory changes in the electric industry including a reversal, discontinuance or delay of the present trend toward competitive markets could affect our competitive position and result in unrecoverable costs adversely affecting our business and results of operations;
- Our profitability is impacted by our affiliated companies' continued authorization to sell power at market-based rates;
- There are uncertainties relating to the operations of the PJM and MISO regional transmission organizations (RTOs);
- Costs of compliance with environmental laws are significant, and the cost of compliance with future environmental laws including limitations on GHG emissions could adversely affect cash flow and profitability;
- Availability and cost of emission credits could materially impact our costs of operations;
- Mandatory renewable portfolio requirements could negatively affect our costs;
- We are and may become subject to legal claims arising from the presence of asbestos or other regulated substances at some of our facilities;
- The continuing availability and operation of generating units is dependent on retaining the necessary licenses, permits, and operating authority from governmental entities, including the NRC;
- Interest rates and/or a credit rating downgrade could negatively affect our financing costs and our ability to access capital;
- We must rely on cash from our subsidiaries; and
- We cannot assure common shareholders that future dividend payments will be made, or if made, in what amounts they may be paid.

RESULTS OF OPERATIONS

The financial results discussed below include revenues and expenses from transactions among our business segments. A reconciliation of segment financial results is provided in Note 16 to the consolidated financial statements. The divested FSG business segment is included in "Other and reconciling adjustments" due to its immaterial impact on prior period financial results. Net income (loss) by reportable business segment was as follows:

	2007	2006	2005	Increase (Decrease) 2007 vs 2006	Increase (Decrease) 2006 vs 2005
	(In millions, except per share amounts)				
Net Income (Loss) By Business Segment:					
Energy delivery services	$ 862	$ 893	$ 987	$ (31)	$ (94)
Competitive energy services	495	393	190	102	203
Ohio transitional generation services	103	112	(73)	(9)	185
Other and reconciling adjustments*	(151)	(144)	(243)	(7)	99
Total	$ 1,309	$ 1,254	$ 861	$ 55	$ 393
Basic Earnings Per Share:					
Income from continuing operations	$ 4.27	$ 3.85	$ 2.68	$ 0.42	$ 1.17
Discontinued operations	-	(0.01)	0.03	0.01	(0.04)
Cumulative effect of a change in accounting principle	-	-	(0.09)	-	0.09
Basic earnings per share	$ 4.27	$ 3.84	$ 2.62	$ 0.43	$ 1.22
Diluted Earnings Per Share:					
Income from continuing operations	$ 4.22	$ 3.82	$ 2.67	$ 0.40	$ 1.15
Discontinued operations	-	(0.01)	0.03	0.01	(0.04)
Cumulative effect of a change in accounting principle	-	-	(0.09)	-	0.09
Diluted earnings per share	$ 4.22	$ 3.81	$ 2.61	$ 0.41	$ 1.20

* Represents other operating segments and reconciling adjustments including interest expense on holding company debt, corporate support services revenues and expenses and the impact of the 2005 Ohio tax legislation.

Summary of Results of Operations – 2007 Compared with 2006

Financial results for our major business segments in 2007 and 2006 were as follows:

2007 Financial Results	Energy Delivery Services	Competitive Energy Services	Ohio Transitional Generation Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ 8,069	$ 1,316	$ 2,559	$ -	$ 11,944
Other	657	152	37	12	858
Internal	-	2,901	-	(2,901)	-
Total Revenues	8,726	4,369	2,596	(2,889)	12,802
Expenses:					
Fuel and purchased power	3,738	1,937	2,240	(2,901)	5,014
Other operating expenses	1,700	1,160	305	(79)	3,086
Provision for depreciation	404	204	-	30	638
Amortization of regulatory assets	991	-	28	-	1,019
Deferral of new regulatory assets	(371)	-	(153)	-	(524)
General taxes	623	107	4	20	754
Total Expenses	7,085	3,408	2,424	(2,930)	9,987
Operating Income	1,641	961	172	41	2,815
Other Income (Expense):					
Investment income	240	16	1	(137)	120
Interest expense	(456)	(172)	(1)	(146)	(775)
Capitalized interest	11	20	-	1	32
Subsidiaries' preferred stock dividends	-	-	-	-	-
Total Other Expense	(205)	(136)	-	(282)	(623)
Income From Continuing Operations Before Income Taxes	1,436	825	172	(241)	2,192
Income taxes	574	330	69	(90)	883
Income from continuing operations	862	495	103	(151)	1,309
Discontinued operations	-	-	-	-	-
Net Income (Loss)	$ 862	$ 495	$ 103	$ (151)	$ 1,309

2006 Financial Results	Energy Delivery Services	Competitive Energy Services	Ohio Transitional Generation Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ 7,039	$ 1,266	$ 2,366	$ -	$ 10,671
Other	584	163	24	59	830
Internal	14	2,609	-	(2,623)	-
Total Revenues	7,637	4,038	2,390	(2,564)	11,501
Expenses:					
Fuel and purchased power	3,015	1,812	2,050	(2,624)	4,253
Other operating expenses	1,585	1,138	247	(5)	2,965
Provision for depreciation	379	190	-	27	596
Amortization of regulatory assets	841	-	20	-	861
Deferral of new regulatory assets	(375)	-	(125)	-	(500)
General taxes	599	90	10	21	720
Total Expenses	6,044	3,230	2,202	(2,581)	8,895
Operating Income	1,593	808	188	17	2,606
Other Income (Expense):					
Investment income	328	35	-	(214)	149
Interest expense	(431)	(200)	(1)	(89)	(721)
Capitalized interest	14	12	-	-	26
Subsidiaries' preferred stock dividends	(16)	-	-	9	(7)
Total Other Expense	(105)	(153)	(1)	(294)	(553)
Income From Continuing Operations Before Income Taxes	1,488	655	187	(277)	2,053
Income taxes	595	262	75	(137)	795
Income from continuing operations	893	393	112	(140)	1,258
Discontinued operations	-	-	-	(4)	(4)
Net Income (Loss)	$ 893	$ 393	$ 112	$ (144)	$ 1,254

Changes Between 2007 and 2006 Financial Results - Increase (Decrease)	Energy Delivery Services	Competitive Energy Services	Ohio Transitional Generation Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
Revenues:					
External					
Electric	$ 1,030	$ 50	$ 193	$ -	$ 1,273
Other	73	(11)	13	(47)	28
Internal	(14)	292	-	(278)	-
Total Revenues	1,089	331	206	(325)	1,301
Expenses:					
Fuel and purchased power	723	125	190	(277)	761
Other operating expenses	115	22	58	(74)	121
Provision for depreciation	25	14	-	3	42
Amortization of regulatory assets	150	-	8	-	158
Deferral of new regulatory assets	4	-	(28)	-	(24)
General taxes	24	17	(6)	(1)	34
Total Expenses	1,041	178	222	(349)	1,092
Operating Income	48	153	(16)	24	209
Other Income (Expense):					
Investment income	(88)	(19)	1	77	(29)
Interest expense	(25)	28	-	(57)	(54)
Capitalized interest	(3)	8	-	1	6
Subsidiaries' preferred stock dividends	16	-	-	(9)	7
Total Other Income (Expense)	(100)	17	1	12	(70)
Income From Continuing Operations Before Income Taxes	(52)	170	(15)	36	139
Income taxes	(21)	68	(6)	47	88
Income from continuing operations	(31)	102	(9)	(11)	51
Discontinued operations	-	-	-	4	4
Net Income (Loss)	$ (31)	$ 102	$ (9)	$ (7)	$ 55

Energy Delivery Services – 2007 Compared to 2006

Net income decreased $31 million (or 3%) to $862 million in 2007 compared to $893 million in 2006, primarily due to higher expenses, partially offset by increased revenues.

Revenues –

The increase in total revenues resulted from the following sources:

Revenues by Type of Service	2007	2006	Increase (Decrease)
		(In millions)	
Distribution services	$ 3,909	$ 3,849	$ 60
Generation sales:			
Retail	3,145	2,774	371
Wholesale	687	247	440
Total generation sales	3,832	3,021	811
Transmission	785	561	224
Other	200	206	(6)
Total Revenues	$ 8,726	$ 7,637	$ 1,089

The change in distribution deliveries by customer class is summarized in the following table:

Distribution KWH Deliveries	
Residential	4.3 %
Commercial	3.7 %
Industrial	(0.2)%
Net Increase in Distribution KWH Deliveries	2.6 %

The increase in electric distribution deliveries to customers was primarily due to higher weather-related usage during 2007 compared to 2006 (heating degree days increased by 11.2% and cooling degree days increased by 16.7%). The higher revenues from increased distribution deliveries were partially offset by distribution rate decreases of $86 million and $21 million for Met-Ed and Penelec, respectively, as a result of a January 11, 2007 PPUC rate decision (see "Regulatory Matters – Pennsylvania").

The following table summarizes the price and volume factors contributing to the $811 million increase in generation sales revenues in 2007 compared to 2006:

Sources of Change in Generation Sales Revenues	Increase (Decrease)
	(In millions)
Retail:	
Effect of 1.7% decrease in sales volumes	$ (48)
Change in prices	419
	371
Wholesale:	
Effect of 120% increase in sales volumes	297
Change in prices	143
	440
Net Increase in Generation Sales Revenues	$ 811

The decrease in retail generation sales volume was primarily due to an increase in customer shopping in Penn's service territory in 2007. The increase in retail generation prices during 2007 compared to 2006 was primarily due to increased generation rates for JCP&L resulting from the New Jersey BGS auction process and an increase in NUGC rates authorized by the NJBPU. Wholesale generation sales increased principally as a result of Met-Ed and Penelec selling additional available power into the PJM market in 2007.

Transmission revenues increased $224 million primarily due to higher transmission rates for Met-Ed and Penelec resulting from the January 2007 PPUC authorization for transmission cost recovery. Met-Ed and Penelec defer the difference between revenues received under their transmission rider and transmission costs incurred, with no material effect on current period earnings (see "Regulatory Matters – Pennsylvania").

Expenses –

The increases in revenues discussed above were offset by an approximate $1.0 billion increase in expenses due to the following:

- Purchased power costs were $723 million higher in 2007 due to increases in both unit costs and volumes purchased. The increased unit costs reflected the effect of higher JCP&L costs resulting from the BGS auction process. The increased volumes purchased in 2007 resulted primarily from Met-Ed's and Penelec's higher sales to the PJM wholesale market. The following table summarizes the sources of changes in purchased power costs:

Sources of Change in Purchased Power	**Increase**
	(In millions)
Purchased Power:	
Change due to increased unit costs	$ 349
Change due to increased volume	248
Decrease in NUG costs deferred	126
Net Increase in Purchased Power Costs	$ 723

- Other operating expenses increased $115 million primarily due to the net effects of:

  - An increase of $101 million in MISO and PJM transmission expenses, resulting primarily from higher congestion costs.

  - An increase in operation and maintenance expenses of $19 million primarily due to increased labor, contractor costs and materials devoted to maintenance projects in 2007.

- Amortization of regulatory assets increased $150 million compared to 2006 due primarily to recovery of deferred BGS costs through higher NUGC rates for JCP&L (as discussed above), recovery of deferred non-NUG stranded costs through application of CTC revenues for Met-Ed and higher transition cost amortization for the Ohio companies.

- The deferral of new regulatory assets during 2007 was $4 million less in 2007 than in 2006 primarily due to $46 million of lower PJM transmission cost deferrals, partially offset by the deferral of previously expensed decommissioning costs of $27 million related to the Saxton nuclear research facility (see "Regulatory Matters – Pennsylvania") and increased carrying charges earned on the Ohio Companies' RCP distribution deferrals of $11 million.

- Depreciation expense increased $25 million and general taxes increased $24 million due primarily to property additions since 2006.

- Other expenses increased $100 million in 2007 compared to 2006 primarily due to lower investment income of $88 million resulting from the repayment of notes receivable from affiliates since 2006, and increased interest expense of $25 million related to new debt issuances by CEI, JCP&L and Penelec. These increased costs were partially offset by the absence of $16 million of preferred stock dividends paid in 2006.

Competitive Energy Services – 2007 Compared to 2006

Net income for this segment increased $102 million to $495 million in 2007 compared to $393 million in 2006. This increase reflected an improvement in generation margin (revenues less fuel and purchased power), partially offset by higher operating expenses, depreciation and general taxes.

Revenues –

Total revenues increased $331 million in 2007 compared to 2006 primarily as a result of higher unit prices for affiliated generation sales to the Ohio Companies and increased retail sales revenues, partially offset by lower non-affiliated wholesale sales revenues.

The higher retail revenues resulted from increased sales in both the MISO and PJM markets. The increase in MISO retail sales primarily reflects FES' increased sales to shopping customers in Penn's service territory. Lower non-affiliated wholesale revenues reflected the effect of decreased generation available for the non-affiliated wholesale market due to increased affiliated company power sales under the Ohio Companies' full-requirements PSA and the partial-requirements PSA with Met-Ed and Penelec.

The increased affiliated company generation revenues reflected both higher unit prices and increased sales volumes. The increase in PSA sales to the Ohio Companies was due to their higher retail generation sales requirements. Unit prices were higher because rates charged under FES' full-requirements PSAs reflect the increases in the Ohio Companies' composite retail generation rates. The higher sales to the Pennsylvania Companies were due to increased Met-Ed and Penelec generation sales requirements. These increases were partially offset by lower sales to Penn due to the implementation of its competitive solicitation process in 2007.

The net increase in reported segment revenues resulted from the following sources:

Revenues by Type of Service	**2007**	**2006**	**Increase (Decrease)**
		(In millions)	
Non-Affiliated Generation Sales:			
Retail	$ 712	$ 590	$ 122
Wholesale	603	676	(73)
Total Non-Affiliated Generation Sales	1,315	1,266	49
Affiliated Generation Sales	2,901	2,609	292
Transmission	103	120	(17)
Other	50	43	7
Total Revenues	$ 4,369	$ 4,038	$ 331

The following tables summarize the price and volume factors contributing to changes in revenues from generation sales:

Source of Change in Non-Affiliated Generation Sales	**Increase (Decrease)**
	(In millions)
Retail:	
Effect of 10.8% increase in sales volumes	$ 63
Change in prices	59
	122
Wholesale:	
Effect of 22.7% decrease in sales volumes	(154)
Change in prices	81
	(73)
Net Increase in Non-Affiliated Generation Sales	$ 49

Source of Change in Affiliated Generation Sales	**Increase**
	(In millions)
Ohio Companies:	
Effect of 3.4% increase in sales volumes	$ 68
Change in prices	118
	186
Pennsylvania Companies:	
Effect of 14.9% increase in sales volumes	87
Change in prices	19
	106
Increase in Affiliated Generation Sales	$ 292

Transmission revenues decreased $17 million due in part to reduced FTR revenue resulting from fewer FTRs allocated by MISO ($15 million) and PJM ($9 million), partially offset by higher retail transmission revenues of $8 million.

Expenses -

Total expenses increased $178 million in 2007 compared to 2006 due to the following factors:

- Purchased power costs increased $159 million due principally to higher volumes for replacement power related to the forced outages at the Bruce Mansfield and Perry Plants and costs associated with the new capacity market in PJM ($25 million).

- Fossil generation operating costs were $66 million higher due to the absence of gains from the sale of emissions allowances recognized in 2006 ($27 million) and increased costs related to scheduled and forced maintenance outages during 2007.

- Lease expenses increased $55 million primarily due to intercompany billings associated with the assignment of CEI's and TE's leasehold interests in the Bruce Mansfield Plant to FGCO and the Bruce Mansfield Unit 1 sale and leaseback transaction completed in 2007.

- Depreciation expenses were $14 million higher due to property additions since 2006.

- General taxes were $17 million higher as a result of increased gross receipts taxes and property taxes.

Partially offsetting the higher costs were:

- Fuel costs were $34 million lower primarily due to reduced coal costs and emission allowance costs, offset by increases in nuclear fuel and natural gas costs. Coal costs were reduced due to $38 million of reduced coal consumption reflecting lower generation. Reduced emission allowance costs ($19 million) were partially offset by increased natural gas costs ($7 million) due to increased consumption and nuclear fuel costs ($15 million) due to increased consumption and higher prices.

- Nuclear generation operating costs were $72 million lower due to fewer outages in 2007 compared to 2006 and reduced employee benefit costs.

- MISO transmission expense decreased by $32 million from 2006 due primarily to a one-time resettlement of costs from generation providers to load serving entities.

- Total other expense in 2007 was $17 million lower than in 2006 primarily due to lower interest expense, partially offset by decreased earnings on nuclear decommissioning trust investments.

Ohio Transitional Generation Services – 2007 Compared to 2006

Net income for this segment decreased to $103 million in 2007 from $112 million in 2006. Higher operating expenses, primarily for purchased power, were partially offset by higher generation revenues.

Revenues –

The increase in reported segment revenues resulted from the following sources:

Revenues by Type of Service	**2007**	**2006**	**Increase (Decrease)**
		(In millions)	
Generation sales:			
Retail	$ 2,248	$ 2,095	$ 153
Wholesale	7	13	(6)
Total generation sales	2,255	2,108	147
Transmission	333	280	53
Other	8	2	6
Total Revenues	$ 2,596	$ 2,390	$ 206

The following table summarizes the price and volume factors contributing to the increase in sales revenues from retail customers:

Source of Change in Generation Sales Revenues	Increase (In millions)
Retail:	
Effect of 3.9% increase in sales volumes	$ 82
Change in prices	71
Total Increase in Retail Generation Sales Revenues	$ 153

The increase in generation sales was primarily due to higher weather-related usage in 2007 compared to 2006 and reduced customer shopping in Ohio. The percentage of generation services provided by alternative suppliers to total sales delivered by the Ohio Companies in their service areas decreased by 5.9 percentage points from 2006. Average prices increased primarily due to higher composite unit prices for returning customers.

Increased transmission revenues resulted from higher sales volumes and a PUCO-approved transmission tariff increase, which became effective July 1, 2007.

Expenses -

Purchased power costs were $190 million higher due primarily to higher unit costs for power purchased from FES. The factors contributing to the higher costs are summarized in the following table:

Source of Change in Purchased Power	Increase (In millions)
Purchases from non-affiliates:	
Change due to increased unit costs	$ -
Change due to volume purchased	4
	4
Purchases from FES:	
Change due to increased unit costs	114
Change due to volume purchased	72
	186
Total Increase in Purchased Power Costs	$ 190

The increase in volumes purchased was due to the higher retail generation sales requirements. The higher unit costs reflect the increases in the Ohio Companies' composite retail generation rates, as provided for under the PSA with FES.

Other operating expenses increased $58 million primarily due to MISO transmission-related expenses. The difference between transmission revenues accrued and transmission expenses incurred is deferred, resulting in no material impact to current period earnings.

Other – 2007 Compared to 2006

Our financial results from other operating segments and reconciling items, including interest expense on holding company debt and corporate support services revenues and expenses, resulted in a $7 million decrease in our net income in 2007 compared to 2006. The decrease includes the net effect of the sale of our interest in First Communications ($13 million, net of taxes), the absence of subsidiaries' preferred stock dividends in 2007 ($9 million) and the absence of a $4 million loss included in 2006 results from discontinued operations (see Note 8).

Summary of Results of Operations – 2006 Compared with 2005

Financial results for our major business segments in 2005 were as follows:

2005 Financial Results	Energy Delivery Services	Competitive Energy Services	Ohio Transitional Generation Services	Other and Reconciling Adjustments	FirstEnergy Consolidated
			(In millions)		
Revenues:					
External					
Electric	$ 7,582	$ 1,410	$ 1,554	$ -	$ 10,546
Other	583	140	14	75	812
Internal	33	2,425	-	(2,458)	-
Total Revenues	8,198	3,975	1,568	(2,383)	11,358
Expenses:					
Fuel and purchased power	2,857	2,100	1,513	(2,458)	4,012
Other operating expenses	1,600	1,177	248	77	3,102
Provision for depreciation	374	187	-	27	588
Amortization of regulatory assets	1,281	-	-	-	1,281
Deferral of new regulatory assets	(314)	-	(91)	-	(405)
General taxes	607	68	19	19	713
Total Expenses	6,405	3,532	1,689	(2,335)	9,291
Operating Income	1,793	443	(121)	(48)	2,067
Other Income (Expense):					
Investment income	262	79	-	(124)	217
Interest expense	(364)	(205)	(1)	(89)	(659)
Capitalized interest	5	14	-	-	19
Subsidiaries' preferred stock dividends	(16)	-	-	-	(16)
Total Other Expense	(113)	(112)	(1)	(213)	(439)
Income From Continuing Operations Before Income Taxes	1,680	331	(122)	(261)	1,628
Income taxes	672	132	(49)	(6)	749
Income from continuing operations	1,008	199	(73)	(255)	879
Discontinued operations	-	-	-	12	12
Cumulative effect of a change in accounting principle	(21)	(9)	-	-	(30)
Net Income (Loss)	$ 987	$ 190	$ (73)	$ (243)	$ 861
Changes Between 2006 and 2005 Financial Results - Increase (Decrease)					
Revenues:					
External					
Electric	$ (543)	$ (144)	$ 812	$ -	$ 125
Other	1	23	10	(16)	18
Internal	(19)	184	-	(165)	-
Total Revenues	(561)	63	822	(181)	143
Expenses:					
Fuel and purchased power	158	(288)	537	(166)	241
Other operating expenses	(15)	(39)	(1)	(82)	(137)
Provision for depreciation	5	3	-	-	8
Amortization of regulatory assets	(440)	-	20	-	(420)
Deferral of new regulatory assets	(61)	-	(34)	-	(95)
General taxes	(8)	22	(9)	2	7
Total Expenses	(361)	(302)	513	(246)	(396)
Operating Income	(200)	365	309	65	539
Other Income (Expense):					
Investment income	66	(44)	-	(90)	(68)
Interest expense	(67)	5	-	-	(62)
Capitalized interest	9	(2)	-	-	7
Subsidiaries' preferred stock dividends	-	-	-	9	9
Total Other Income (Expense)	8	(41)	-	(81)	(114)
Income From Continuing Operations Before Income Taxes	(192)	324	309	(16)	425
Income taxes	(77)	130	124	(131)	46
Income from continuing operations	(115)	194	185	115	379
Discontinued operations	-	-	-	(16)	(16)
Cumulative effect of a change in accounting principle	21	9	-	-	30
Net Income (Loss)	$ (94)	$ 203	$ 185	$ 99	$ 393

Energy Delivery Services – 2006 Compared with 2005

Net income decreased $94 million (or 10%) to $893 million in 2006 compared to $987 million in 2005, primarily due to decreased revenues and increased purchased power costs partially offset by lower amortization of regulatory assets and increased deferral of new regulatory assets.

Revenues –

The decrease in total revenues resulted from the following sources:

Revenues By Type of Service	2006	2005	Increase (Decrease)
		(In millions)	
Distribution services	$ 3,850	$ 4,582	$ (732)
Generation sales:			
Retail	2,774	2,514	260
Wholesale	247	318	(71)
Total generation sales	3,021	2,832	189
Transmission	560	574	(14)
Other	206	210	(4)
Total Revenues	$ 7,637	$ 8,198	$ (561)

Decreases in distribution deliveries by customer class are summarized in the following table:

Distribution KWH Deliveries	
Residential	(3.9)%
Commercial	(1.4)%
Industrial	(1.4)%
Total Distribution KWH Deliveries	(2.3)%

The completion of our Ohio Companies' and Penn's generation transition cost recovery under their respective transition plans in 2005 were the primary reasons for the decrease in distribution unit prices, which, in conjunction with lower KWH deliveries, resulted in lower distribution delivery revenues. These reductions were partially offset by the elimination of customer shopping incentives in 2006 in Ohio. The costs of these incentives (reported as a reduction to revenues) were deferred for future recovery under our transition plans and did not affect earnings. The decreases in deliveries to customers were primarily due to milder weather during 2006 as compared to 2005. The following table summarizes major factors producing the $732 million decrease in distribution service revenues in 2006 compared to 2005:

Sources of Change in Distribution Revenues	Increase (Decrease)
	(In millions)
Changes in customer usage	$ (221)
Ohio shopping incentives	222
Reduced Ohio transition rates	(817)
Other	84
Net Decrease in Distribution Revenues	$ (732)

The following table summarizes the price and volume factors contributing to the $189 million increase in generation sales in 2006 compared to 2005:

Sources of Change in Generation Sales Revenues	Increase (Decrease)
	(In millions)
Retail:	
Effect of 0.2% increase in customer usage	$ 4
Change in prices	256
	260
Wholesale:	
Effect of 0.8% decrease in sales	(3)
Change in prices	(68)
	(71)
Net Increase in Generation Sales Revenues	$ 189

Higher retail prices in 2006 compared to 2005 resulted from increased generation rates for JCP&L from the New Jersey BGS auction.

Expenses –

The net decreases in revenues discussed above were partially offset by a $361 million decrease in expenses due to the following:

- Purchased power costs were $163 million higher in 2006 due to higher unit prices partially offset by a 1.1% decrease in volumes purchased. The increased unit prices primarily reflected the effect of higher JCP&L purchased power unit prices resulting from the BGS auction. The decrease in volumes purchased in 2006 was principally due to lower generation sales requirements in the JCP&L service area. The following table summarizes the sources of changes in purchased power costs:

Sources of Change in Purchased Power	**Increase (Decrease)** *(In millions)*
Purchased Power:	
Change due to increased unit costs	$ 222
Change due to decreased volume	(34)
Decrease in NUG costs deferred	(25)
Net Increase in Purchased Power Costs	$ 163

- Other operating expenses were $15 million lower in 2006 due, in part, to the following factors:
  - The absence in 2006 of expenses for refunds to third-party providers of ancillary services as a result of the implementation of the Ohio Companies' RCP in 2006. Under the RCP, third-party suppliers of ancillary services now bill customers directly for those services. In 2005, ancillary service refund expense was $27 million; and
  - A $52 million decrease in employee and contractor costs resulting from lower storm-related expenses and the decreased use of outside contractors for tree trimming, reliability work, legal services and jobbing and contracting; offset by
  - A $58 million increase in other expenses due, in part, to increased corporate support service costs of $19 million, a $32 million increase in material and supplies costs applicable to operating and maintenance activities in 2006 and the absence in 2006 of a $9 million insurance settlement received in 2005.
- Depreciation expense was $5 million higher resulting principally from increased depreciable property additions;
- Amortization of regulatory assets decreased $440 million resulting from the completion of Ohio generation transition cost recovery and Penn's transition plan in 2005;
- Deferral of new regulatory assets increased $61 million due to the distribution cost deferrals authorized under the Ohio Companies' RCP, and PJM costs incurred that will be recovered from customers through future rates, partially offset by the completion of shopping incentive deferrals under the Ohio Companies' transition plan and the absence of new regulatory assets resulting from the 2005 rate decision for JCP&L;
- General taxes decreased by $8 million primarily due to lower property taxes; and
- Other expense decreased $8 million in 2006 compared to 2005 due to increased investment income and capitalized interest, partially offset by increased interest expense resulting primarily from the Ohio Companies' 2006 long-term debt issuances.

Competitive Energy Services – 2006 Compared with 2005

Net income for this segment increased $203 million to $393 million in 2006 compared to $190 million in 2005. An improvement in generation margin (revenues less fuel and purchased power) and lower operating expenses was partially offset by higher general taxes and reduced investment income.

Revenues –

Revenues increased by $63 million in 2006 compared to the prior year due to increases in generation sales to affiliates which were partially offset by decreased non-affiliated generation sales. Affiliated generation sales to the Ohio Companies through PSA arrangements increased by $517 million primarily as a result of higher unit prices. Unit prices were higher because rates charged under FES' full-requirements PSAs reflect the increases in the Ohio Companies' composite retail generation rates. The PSA revenue increase also reflected a 4.9% increase in sales resulting from the Ohio Companies' higher retail generation sales requirements. The higher PSA sales revenues from the Ohio Companies were partially offset by a $333 million decrease in generation sales to Pennsylvania and New Jersey affiliates. This decrease was due to a 41.4% decrease in sales volumes, partially offset by higher unit prices. The lower sales were due to lower contractual sales requirements from FES to its PJM market affiliates and decreased generation sales requirements in the JCP&L service area in 2006 compared to 2005.

Non-affiliated generation sales revenues decreased in both the retail and wholesale markets in 2006 compared to 2005. The lower retail sales revenues were due to a 17.3% decrease in customer usage, partially offset by higher unit prices. The lower sales reflected a decrease in the shopping customers FES was serving as those customers returned to the Ohio Companies for their generation requirements. Our record generation output in 2006 allowed for a 9.3% increase in wholesale sales as compared to 2005. However, these sales increases were more than offset by lower unit prices in the wholesale market, resulting in a $79 million decrease in wholesale revenues in 2006.

Transmission revenues increased $43 million in 2006 compared to 2005 due primarily to higher transmission volumes.

Changes in revenues in 2006 from the prior year are summarized in the following table:

Revenues By Type of Service	**2006**	**2005**	**Increase (Decrease)**
		(In millions)	
Non-affiliated generation sales:			
Retail	$ 590	$ 656	$ (66)
Wholesale	676	755	(79)
Total non-affiliated generation sales	1,266	1,411	(145)
Affiliated generation sales	2,609	2,425	184
Transmission	120	77	43
Other	43	62	(19)
Total Revenues	$ 4,038	$ 3,975	$ 63

The following tables summarize the price and volume factors contributing to changes in revenues from generation sales:

Source of Change in Non-Affiliated Generation Sales	**Increase (Decrease)**
	(In millions)
Retail:	
Effect of 17.3% decrease in customer usage	$ (114)
Change in prices	48
	(66)
Wholesale:	
Effect of 9.3% increase in sales	70
Change in prices	(149)
	(79)
Net Decrease in Non-Affiliated Generation Sales	$ (145)

Source of Change in Affiliated Generation Sales	**Increase (Decrease)**
	(In millions)
Ohio Companies:	
Effect of 4.9% increase in sales	$ 74
Change in prices	443
	517
Pennsylvania and New Jersey affiliates:	
Effect of 41.4% decrease in sales	(379)
Change in prices	46
	(333)
Net Increase in Affiliated Generation Sales	$ 184

Expenses -

Total expenses decreased by $302 million in 2006 compared to 2005. The decrease was primarily due to lower purchased power costs, partially offset by higher fuel costs.

The following table summarizes the factors contributing to the changes in fuel and purchased power costs.

Source of Change in Fuel and Purchased Power	Increase (Decrease) (In millions)
Fuel:	
Change due to increased composite unit costs	$ 75
Change due to volume consumed	24
	99
Purchased Power:	
Change due to increased unit costs	54
Change due to volume purchased	(441)
	(387)
Net Decrease in Fuel and Purchased Power Costs	$ (288)

The net decrease in expenses was due to the following factors:

- Lower purchased power costs as a result of decreased KWH purchases, partially offset by increased unit costs. KWH purchases in 2006 were 45% lower than 2005 due to reduced generation sales requirements to affiliates in the PJM market and increased power available from our owned generation facilities;

- Lower transmission expenses and credits from the sale of emission allowances. The decrease in transmission expenses was due to lower PJM congestion and ancillary charges, reflecting the lower sales to affiliates in PJM discussed above, and lower MISO transmission expenses; and

- The absence in 2006 of the 2005 accruals of (1) $8.5 million for a civil penalty related to the Sammis Plant; (2) $10 million for obligations to fund environmentally beneficial projects in connection with the Sammis NSR settlement; and (3) $31.5 million for a civil penalty related to the extended Davis-Besse outage.

The above decreases were partially offset by:

- Higher fuel costs of $99 million resulting from our generation fleet's record output in 2006. Fossil fuel costs increased $97 million as a result of increased generation output, higher coal prices and increased transportation costs for western coal. The increased coal costs were partially offset by lower natural gas and emission allowance costs. Nuclear fuel costs were higher by $2 million in 2006 compared to the prior year principally due to higher unit prices;

- An increase in nuclear operating expenses of $55 million due to three refueling outages in 2006 compared with two refueling outages in 2005;

- Increased depreciation expenses of $3 million as a result of property additions; and

- Higher general taxes of $22 million reflecting increased property taxes.

Other Income –

Investment income in 2006 was $44 million lower than in 2005 primarily due to decreased earnings on nuclear decommissioning trust investments.

Ohio Transitional Generation Services – 2006 Compared with 2005

Net income for this segment increased $185 million to $112 million in 2006 compared to a loss of $73 million in 2005. Higher retail generation revenues in 2006 were partially offset by higher operating expenses, primarily for purchased power.

Revenues –

The increase in reported segment revenues resulted from the following sources:

Revenues By Type of Service	2006	2005	Increase (Decrease)
		(In millions)	
Generation sales:			
Retail	$ 2,095	$ 1,050	$ 1,045
Wholesale	13	339	(326)
Total generation sales	2,108	1,389	719
Transmission	280	173	107
Other	2	6	(4)
Total Revenues	$ 2,390	$ 1,568	$ 822

The following table summarizes the price and volume factors contributing to the increase in generation sales revenues:

Sources of Change in Generation Sales Revenues	Increase (Decrease)
	(In millions)
Retail:	
Effect of 24.9% increase in customer usage	$ 261
Change in prices	784
	1,045
Wholesale:	
Effect of 93.7% decrease in sales	(318)
Change in prices	(8)
	(326)
Net Increase in Generation Sales Revenues	$ 719

The retail generation revenue increase was primarily due to higher unit prices resulting from implementation in 2006 of the rate stabilization and fuel recovery charges under the Ohio Companies' RCP. Higher retail revenues also reflected the 24.9% increase in retail KWH sales due principally to the return of shopping customers as a result of third-party suppliers leaving the northern Ohio marketplace. The lower wholesale revenues in 2006 were principally due to the termination of an OE non-affiliated wholesale sales agreement ($179 million) and the December 2005 completion of the Ohio Companies' MSG sales arrangement under the Ohio transition plan ($134 million). The Ohio Companies had been required to provide the MSG to certain non-affiliated alternative suppliers.

Increased transmission revenues resulted from approximately $107 million of new revenues under a MISO transmission rider that began in 2006.

Expenses -

Purchased power costs were $537 million higher due primarily to higher unit prices for power purchased from FES. The factors contributing to the higher costs are summarized in the following table:

Source of Change in Purchased Power	Increase (Decrease)
	(In millions)
Purchases from non-affiliates:	
Change due to increased unit costs	$ 21
Change due to volume	(1)
	20
Purchases from FES:	
Change due to increased unit costs	443
Change due to volume	74
	517
Total Increase in Purchased Power Costs	$ 537

The increase in volumes purchased was due to the higher retail generation sales requirements. The higher unit costs resulted from the provision of the full-requirements PSA with FES under which purchased power unit costs reflected the increases in the Ohio Companies' composite retail generation sales unit prices.

The increased deferral of new regulatory assets in 2006 resulted from the deferral of fuel costs ($110 million) under the RCP, partially offset by lower MISO cost deferrals ($75 million). Amortization of regulatory assets of $20 million in 2006 represented the amortization of MISO costs for which recovery began in 2006.

Other – 2006 Compared to 2005

Our financial results from other operating segments and reconciling adjustments, including interest expense on holding company debt and corporate support services revenues and expenses, resulted in a $99 million increase to our net income in 2006 compared to 2005. The increase was primarily due to the following:

- The absence of 2005 income tax expenses of $63 million consisting of the write-off of income tax benefits of $51 million due to the 2005 change in Ohio tax legislation and $12 million due to a 2005 JCP&L tax audit adjustment;

- $23 million of 2006 income tax benefits, primarily reflecting the 2005 federal income tax return filed in the third quarter of 2006 and the Ohio tax benefit related to a voluntary $300 million pension plan contribution (see Note 3);

- A $3 million gain related to interest rate swap financing arrangements; and

- A $14 million increase in investment income in 2006.

These increases were partially offset by securities redemption charges of $16 million in 2006, a $5 million decrease in gas commodity transaction results and the absence of net gains of $9 million from the sale of non-core assets in 2005.

DISCONTINUED OPERATIONS

Discontinued operations for 2006 include the remaining FSG subsidiaries (Hattenbach, Dunbar, Edwards, and RPC) and a portion of MYR. We sold 60% of MYR in March 2006 and began accounting for our remaining interest in MYR under the equity method of accounting for investments. An additional 1.67% was sold in June 2006 and the remaining 38.33% was sold in November 2006. MYR's results prior to the sale of the initial 60% in March 2006 and the gain on the March sale is included in discontinued operations. The 2006 MYR results subsequent to the March 2006 sale, recorded as equity investment income, and the gain on the November sale are included in income from continuing operations. Discontinued operations for 2005 include FSG subsidiaries (Elliott-Lewis, Spectrum Control Systems and L.H. Cranston and Sons) and the natural gas business of FES.

The following table summarizes the sources of income from discontinued operations:

Discontinued Operations (Net of tax)	2006	2005
	(In millions)	
Gain on sale:		
FES natural gas business	$ -	$ 5
FSG subsidiaries	2	12
Reclassification of operating (loss) income to discontinued operations:		
FSG subsidiaries	(8)	(4)
MYR	2	(1)
Income (loss) from discontinued operations	$ (4)	$ 12

POSTRETIREMENT BENEFITS

Strengthened equity markets during 2007, $1.3 billion of voluntary cash pension contributions made since September 2004 and plan amendments contributed to reductions of $127 million and $27 million in postretirement benefits expenses in 2007 and 2006, respectively, from the prior year. The following table reflects the portion of qualified pension and OPEB costs that were charged to expense in 2007, 2006 and 2005:

Postretirement Benefits Costs (Credits)	2007	2006	2005
		(In millions)	
Pension	$ (9)	$ 29	$ 32
OPEB	(41)	48	72
Total	$ (50)	$ 77	$ 104

Pension and OPEB expenses are included in various cost categories and have contributed to cost decreases discussed above for 2007. In 2008, we will increase the share of coinsurance, as well as increase the health care premiums paid by certain retirees, which will continue to reduce OPEB costs in 2008. See "Critical Accounting Policies - Pension and Other Postretirement Benefits Accounting" for a discussion of the impact of underlying assumptions on postretirement expenses.

SUPPLY PLAN

The Companies have a default service obligation to provide generation to non-shopping customers who have elected to continue to receive generation service under regulated retail tariffs. The volume of these sales can vary depending on the level of shopping that occurs. The Companies procure their power through PSAs with FES, contracts with non-affiliated companies and, in the case of JCP&L and Penn, through state approved competitive procurement processes. Geographically, approximately 66% of the total generation service obligation is for customers located in the MISO market area and 34% for customers located in the PJM market area.

Within the franchise territories of the Companies, alternative retail energy suppliers are expected in 2008 to provide generation service for approximately 3,345 MW (summer peak) of load with an estimated energy requirement of 15,300 million KWH. If these alternative suppliers fail to deliver power to their customers located in one of the Companies' service areas, our utility subsidiary must procure replacement power in the role of PLR.

FES and the Companies control (either through ownership, lease or participation in OVEC) 14,127 MW of installed generating capacity. The balance of the Companies' 2008 expected generation service obligation has been secured by FES through a combination of long-term purchases (contract term of greater than one year) and short-term purchases (contract term of less than one year). Additional power supply requirements will be met through spot market transactions.

CAPITAL RESOURCES AND LIQUIDITY

Our business is capital intensive and requires considerable capital resources to fund operating expenses, construction expenditures, scheduled debt maturities and interest and dividend payments. In 2008 and subsequent years, we expect to meet our contractual obligations and other cash requirements primarily with a combination of cash from operations and funds from the capital markets. We also expect that borrowing capacity under credit facilities will continue to be available to manage working capital requirements during those periods.

As of December 31, 2007, our net deficit in working capital (current assets less current liabilities) was principally due to the classification of certain variable interest rate PCRBs as currently payable long-term debt. These currently bear interest in an interest rate mode that permits individual debt holders to put the respective debt back to the issuer for purchase prior to maturity (see Note 11(C)).

Changes in Cash Position

Our primary source of cash required for continuing operations as a holding company is cash from the operations of our subsidiaries. We also have access to $2.75 billion of short-term financing under a revolving credit facility which expires in 2012. In 2007, we received $1.3 billion of cash dividends and return of capital from our subsidiaries and paid $616 million in cash dividends to our common stockholders. With the exception of Met-Ed, which is currently in an accumulated deficit position, there are no material restrictions on the payment of cash dividends by our subsidiaries.

On March 2, 2007, we repurchased approximately 14.4 million shares, or approximately 4.5%, of our outstanding common stock at a total final price of approximately $942 million pursuant to an accelerated share repurchase program. The initial $891 million purchase price was adjusted by a $51 million cash payment on December 13, 2007. The share repurchase was funded with short-term borrowings, the initial portion of which has since been repaid with the proceeds from the Bruce Mansfield Unit 1 sale and leaseback transaction discussed below.

On July 13, 2007, FGCO completed the sale and leaseback of its 93.825% undivided interest in Bruce Mansfield Unit 1, representing 779 MW of net demonstrated capacity. The purchase price of approximately $1.329 billion (net after-tax proceeds of approximately $1.2 billion) for the undivided interest was funded through a combination of equity investments by affiliates of AIG Financial Products Corp. and Union Bank of California, N.A. in six lessor trusts and proceeds from the sale of $1.135 billion aggregate principal amount of 6.85% pass through certificates due 2034. A like principal amount of secured notes maturing June 1, 2034 were issued by the lessor trusts to the pass through trust that issued and sold the certificates. The lessor trusts leased the undivided interest back to FGCO for a term of approximately 33 years under substantially identical leases (see Notes 6 and 15).

As of December 31, 2007, we had $129 million of cash and cash equivalents compared with $90 million as of December 31, 2006. The major sources of changes in these balances are summarized below.

Cash Flows From Operating Activities

Net cash provided from operating activities was $1.7 billion in 2007, $1.9 billion in 2006 and $2.2 billion in 2005, summarized as follows:

Operating Cash Flows	2007	2006	2005
		(In millions)	
Net income	$ 1,309	$ 1,254	$ 861
Non-cash charges	670	783	1,289
Pension trust contribution*	(300)	90	(341)
Working capital and other	15	(188)	411
Net cash provided from operating activities	$ 1,694	$ 1,939	$ 2,220

* The pension trust contribution in 2005 is net of $159 million of related current year cash income tax benefits. The $90 million cash inflow in 2006 represents reduced income taxes paid in 2006 relating to the $300 million pension trust contribution made in January 2007.

Net cash provided from operating activities decreased by $245 million in 2007 compared to 2006 primarily due to a $300 million pension trust contribution in 2007 and a $113 million change in non-cash charges, partially offset by a $203 million change in working capital and other and a $55 million increase in net income (see "Results of Operations"). The changes in working capital and other primarily resulted from changes in accrued taxes of $246 million and materials and supplies of $104 million due to lower coal inventory levels, partially offset by changes in receivables of $241 million due to higher sales and changes in accounts payable of $48 million reflecting a change in the timing of payments from 2006.

Net cash provided from operating activities decreased by $281 million in 2006 compared to 2005 primarily due to a $599 million decrease from working capital and a $506 million decrease in non-cash charges. These decreases were partially offset by the tax benefit in 2006 relating to the January 2007 pension contribution and the absence in 2006 of the pension trust contribution in 2005 and higher net income in 2006 compared to 2005 (see "Results of Operations"). The decrease from working capital changes primarily resulted from the absence of $242 million of funds received in 2005 for prepaid electric service (under a three-year Energy for Education Program with the Ohio Schools Council), increased tax payments of $325 million, and $273 million of cash collateral returned to suppliers. These decreases were partially offset by an increase in working capital from the collection of receivables of $192 million.

Cash Flows From Financing Activities

In 2007, 2006 and 2005, net cash used for financing activities was $1.3 billion, $804 million and $876 million, respectively, primarily reflecting the redemptions of debt, common stock and preferred stock shown below:

Securities Issued or Redeemed	2007	2006	2005
		(In millions)	
New Issues			
Pollution control notes	$ 427	$ 1,157	$ 721
Senior secured notes	-	382	-
Unsecured notes	1,100	1,200	-
	$ 1,527	$ 2,739	$ 721
Redemptions			
First mortgage bonds	$ 288	$ 41	$ 252
Pollution control notes	432	1,189	555
Senior secured notes	225	206	94
Long-term revolving credit	-	-	215
Unsecured notes	153	1,100	308
Common stock	969	600	-
Preferred stock	-	193	170
	$ 2,067	$ 3,329	$ 1,594
Short-term borrowings (repayments), net	$ (205)	$ 386	$ 561

We had approximately $903 million of short-term indebtedness as of December 31, 2007 compared to approximately $1.1 billion as of December 31, 2006. Available bank borrowing capability as of December 31, 2007 included the following:

Borrowing Capability	(In millions)
Short-term credit facilities[1]	$ 2,870
Accounts receivable financing facilities	550
Utilized	(900)
LOCs	(73)
Net available capability	$ 2,447

[1] Includes the $2.75 billion revolving credit facility described below, a $100 million revolving credit facility that expires in December 2009 and a $20 million uncommitted line of credit.

As of December 31, 2007, the Ohio Companies and Penn had the aggregate capability to issue approximately $3.4 billion of additional FMB on the basis of property additions and retired bonds under the terms of their respective mortgage indentures. The issuance of FMB by OE, CEI and TE is also subject to provisions of their senior note indentures generally limiting the incurrence of additional secured debt, subject to certain exceptions that would permit, among other things, the issuance of secured debt (including FMB) (i) supporting pollution control notes or similar obligations, or (ii) as an extension, renewal or replacement of previously outstanding secured debt. In addition, these provisions would permit OE, CEI and TE to incur additional secured debt not otherwise permitted by a specified exception of up to $573 million, $442 million and $118 million, respectively, as of December 31, 2007. JCP&L satisfied the provision of its senior note indenture for the release of all FMBs held as collateral for senior notes in May 2007, subsequently repaid its other remaining FMBs and, effective September 14, 2007, discharged and released its mortgage indenture.

The applicable earnings coverage tests in the respective charters of OE, TE, Penn and JCP&L are currently inoperative. In the event that any of them issues preferred stock in the future, the applicable earnings coverage test will govern the amount of preferred stock that may be issued. CEI, Met-Ed and Penelec do not have similar restrictions and could issue up to the number of preferred shares authorized under their respective charters.

As of December 31, 2007, we had approximately $1.0 billion of remaining unused capacity under an existing shelf registration statement filed with the SEC in 2003 to support future securities issuances. The shelf registration that expires in December 2008, provides the flexibility to issue and sell various types of securities, including common stock, debt securities, and share purchase contracts and related share purchase units. As of December 31, 2007, OE had approximately $400 million of capacity remaining unused under a shelf registration for unsecured debt securities filed with the SEC in 2006 and will expire in April 2009.

We along with certain of our subsidiaries are party to a $2.75 billion five-year revolving credit facility (included in the borrowing capability table above). We have the capability to request an increase in the total commitments available under this facility up to a maximum of $3.25 billion. Commitments under the facility are available until August 24, 2012, unless the lenders agree, at the request of the borrowers, to an unlimited number of 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 sub-limit, as well as applicable regulatory and other limitations.

The following table summarizes the borrowing sub-limits for each borrower under the facility, as well as the limitations on short-term indebtedness applicable to each borrower under current regulatory approvals and applicable statutory and/or charter limitations:

Borrower	Revolving Credit Facility Sub-Limit	Regulatory and Other Short-Term Debt Limitations[1]
	(In millions)	
FirstEnergy	$ 2,750	$ -[2]
OE	500	500
Penn	50	42
CEI	250[3]	500
TE	250[3]	500
JCP&L	425	422
Met-Ed	250	250[4]
Penelec	250	250[4]
FES	1,000	-[2]
ATSI	-[5]	50

(1) As of December 31, 2007.
(2) No regulatory approvals, statutory or charter limitations applicable.
(3) Borrowing sub-limits for CEI and TE may be increased to up to $500 million by delivering notice to the administrative agent that such borrower has senior unsecured debt ratings of at least BBB by S&P and Baa2 by Moody's.
(4) Excluding amounts which may be borrowed under the regulated money pool.
(5) The borrowing sub-limit for ATSI may be increased up to $100 million by delivering notice to the administrative agent that either (i) such borrower has senior unsecured debt ratings of at least BBB- by S&P and Baa3 by Moody's or (ii) FirstEnergy has guaranteed the obligations of such borrower under the facility.

The revolving credit facility, combined with an aggregate $550 million (unused as of December 31, 2007) of accounts receivable financing facilities for OE, CEI, TE, Met-Ed, Penelec and Penn, are intended to provide liquidity to meet our working capital requirements and for other general corporate purposes.

Under the revolving credit facility, borrowers may request the issuance of LOCs expiring up to one year from the date of issuance. The stated amount of outstanding LOCs 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%, measured at the end of each fiscal quarter. As of December 31, 2007, our debt to total capitalization ratios (as defined under the revolving credit facility) were as follows:

Borrower	
FirstEnergy	57%
OE	44%
Penn	25%
CEI	60%
TE	40%
JCP&L	30%
Met-Ed	44%
Penelec	48%
FES	55%

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

Our regulated companies also have the ability to borrow from each other and the holding company to meet their short-term working capital requirements. A similar but separate arrangement exists among our unregulated companies. FESC administers these two money pools and tracks surplus funds of our respective regulated and unregulated subsidiaries, as well as proceeds available from bank borrowings. Companies receiving a loan under the money pool agreements must repay the principal amount of the loan, together with accrued interest, within 364 days of borrowing the funds. The rate of interest is the same for each company receiving a loan from their respective pool and is based on the average cost of funds available through the pool. The average interest rate for borrowings in 2007 was approximately 5.53% for both money pools.

Our access to capital markets and costs of financing are influenced by the ratings of our securities. The following table displays our securities ratings along with those of FES and the Companies as of December 31, 2007. The ratings outlook from S&P on all securities is negative. The ratings outlook from Moody's on all securities is stable.

Issuer	Securities	S&P	Moody's
FirstEnergy	Senior unsecured	BBB-	Baa3
OE	Senior unsecured	BBB-	Baa2
CEI	Senior secured	BBB+	Baa2
	Senior unsecured	BBB-	Baa3
TE	Senior unsecured	BBB-	Baa3
Penn	Senior secured	A-	Baa1
JCP&L	Senior unsecured	BBB	Baa2
Met-Ed	Senior unsecured	BBB	Baa2
Penelec	Senior unsecured	BBB	Baa2
FES	Corporate Credit/Issuer Rating	BBB	Baa2

On February 21, 2007, we made a $700 million equity investment in FES, all of which was subsequently contributed to FGCO and used to pay down generation asset transfer-related promissory notes owed to the Ohio Companies and Penn. OE used its $500 million of proceeds to repurchase shares of its common stock from FirstEnergy.

On March 27, 2007, CEI issued $250 million of 5.70% unsecured senior notes due 2017. The proceeds of the offering were used to reduce CEI's short-term borrowings and for general corporate purposes.

On May 21, 2007, JCP&L issued $550 million of senior unsecured debt securities, consisting of $250 million of 5.65% senior notes due 2017 and $300 million of 6.15% senior notes due 2037. A portion of the proceeds of the offering were used to redeem outstanding FMB – $125 million principal amount of 7.50% series due 2023 and $150 million principal amount of 6.75% series due 2025. On July 1, 2007, JCP&L also redeemed the remaining $12.2 million of its outstanding FMB. In addition, $125 million of proceeds were used to repurchase shares of its common stock from FirstEnergy. The remaining proceeds were used for general corporate purposes.

As described above, on July 13, 2007, FGCO completed the sale and leaseback of a 93.825% undivided interest in Unit 1 of the Bruce Mansfield Plant. Net after-tax proceeds of approximately $1.2 billion from the transaction were used to repay short-term borrowings from, and to invest in, our unregulated companies' money pool. The repayments and investment allowed FES to reduce its investment in that money pool in order to repay approximately $250 million of external bank borrowings and fund a $600 million equity repurchase from us. We used these funds to reduce our external short-term borrowings as discussed above.

On August 30, 2007, Penelec issued $300 million of 6.05% unsecured senior notes due 2017. A portion of the net proceeds from the issuance and sale of the senior notes was used to fund the repurchase of $200 million of Penelec's common stock from FirstEnergy. The remaining net proceeds were used to repay short-term borrowings and for general corporate purposes.

On October 4, 2007, FGCO and NGC closed on the issuance of approximately $248 million and $180 million, respectively, of PCRBs. The PCRBs were issued through the OAQDA (FGCO – $241 million; NGC – $26 million), OWDA (FGCO – $7 million; NGC – $55 million) and BCIDA (NGC – $99 million) with the benefit of bond insurance policies issued by Ambac Assurance Corporation and initially bear interest in an auction rate mode, which provided for a weighted average interest rate of approximately 4.3% and 10.2% as of December 31, 2007 and February 26, 2008, respectively. Proceeds from the issuances were used to redeem, during the fourth quarter of 2007, an equal amount of outstanding PCRBs originally issued by those authorities on behalf of the Ohio Companies. This transaction brings the total amount of PCRBs transferred from the Ohio Companies and Penn to FGCO and NGC to approximately $1.9 billion, with approximately $265 million remaining to be transferred. The transfer of these PCRBs supports the intra-system generation asset transfer that was completed in 2005.

As of December 31, 2007, FGCO, NGC, Met-Ed, and Penelec had $276 million, $180 million, $29 million, and $45 million, respectively, of tax-exempt long-term debt sold at auction rates that are reset every 7 or 35 days and insured by AAA-rated bond insurers, namely Ambac Assurance Corporation (Ambac) and XL Capital Assurance, Inc. (XL Capital). Due to the exposure that these bond insurers have in connection with recent developments in the subprime credit market, the rating agencies have put these insurers on review for possible downgrade. Fitch has since lowered the credit ratings of Ambac from AAA to AA and XL Capital from AAA to A. Moody's has downgraded the credit rating of XL Capital from Aaa to A3. Because of the apparent widespread loss of confidence in the creditworthiness of these bond insurers and a resulting loss of liquidity in the markets for these types of insured auction rate securities generally, like other issuers and obligors in this market, we have experienced higher auction rate resets and in some cases failed auctions. The instruments under which the bonds are issued, however, allow us to convert to other interest rate modes, including short-term variable-rate or longer term fixed-rate mode, and in February 2008, we elected to convert all of our outstanding auction-rate bonds to a weekly rate mode, which requires our mandatory purchase of these bonds on the applicable conversion dates. The conversion and purchase of the auction rate bonds is expected to be completed in April 2008. We expect to hold the bonds until they can be remarketed or refinanced under a different interest rate mode.

Cash Flows From Investing Activities

Net cash flows used in investing activities resulted principally from property additions. Energy delivery services expenditures for property additions primarily include expenditures related to transmission and distribution facilities. Capital expenditures by the competitive energy services segment are principally generation-related. The following table summarizes investing activities for the three years ended December 31, 2007 by business segment:

Summary of Cash Flows Used for Investing Activities By Segment	Property Additions	Investments	Other	Total
2007 Sources (Uses)		*(In millions)*		
Energy delivery services	$ (814)	$ 53	$ (6)	$ (767)
Competitive energy services	(740)	1,302	(3)	559
Other	(79)	-	(11)	(90)
Inter-Segment reconciling items	-	(15)	-	(15)
Total	$ (1,633)	$ 1,340	$ (20)	$ (313)
2006 Sources (Uses)				
Energy delivery services	$ (629)	$ 147	$ (10)	$ (492)
Competitive energy services	(644)	(5)	(1)	(650)
Other	(42)	73	11	42
Inter-Segment reconciling items	-	(9)	-	(9)
Total	$ (1,315)	$ 206	$ -	$ (1,109)
2005 Sources (Uses)				
Energy delivery services	$ (782)	$ (106)	$ (14)	$ (902)
Competitive energy services	(375)	(4)	3	(376)
Other	(51)	28	(20)	(43)
Inter-Segment reconciling items	-	(12)	-	(12)
Total	$ (1,208)	$ (94)	$ (31)	$ (1,333)

Net cash used for investing activities in 2007 decreased by $796 million compared to 2006. The decrease was principally due to approximately $1.3 billion in proceeds from the Bruce Mansfield Unit 1 sale and leaseback transaction. Partially offsetting the cash proceeds from the sale and leaseback transaction was a $318 million increase in property additions which reflects AQC system and distribution system reliability program expenditures and a $49 million decrease in cash provided from cash investments, primarily from the use of restricted cash investments to repay debt during 2006.

Net cash used for investing activities in 2006 decreased by $224 million compared to 2005. The decrease was principally due to a $58 million increase in proceeds from asset sales (see Note 8), an $86 million decrease in net nuclear decommissioning trust activities due to the completion of the Ohio Companies' and Penn's transition cost recovery for nuclear decommissioning at the end of 2005 and a $163 million decrease in cash investments described above. These decreases were partially offset by a $107 million increase in property additions, including the replacement of the steam generators and reactor head at Beaver Valley Unit 1 and AQC system expenditures.

Our capital spending for the period 2008-2012 is expected to be nearly $7.6 billion (excluding nuclear fuel), of which $2.0 billion applies to 2008. Investments for additional nuclear fuel during the 2008-2012 period are estimated to be approximately $1.4 billion, of which about $132 million applies to 2008. During the same period, our nuclear fuel investments are expected to be reduced by approximately $952 million and $111 million, respectively, as the nuclear fuel is consumed.

CONTRACTUAL OBLIGATIONS

As of December 31, 2007, our estimated cash payments under existing contractual obligations that we consider firm obligations are as follows:

Contractual Obligations	Total	2008	2009-2010	2011-2012	Thereafter
			(In millions)		
Long-term debt	$ 10,891	$ 334	$ 486	$ 1,583	$ 8,488
Short-term borrowings	903	903	-	-	-
Interest on long-term debt [1]	9,425	628	1,204	1,070	6,523
Operating leases [2]	4,813	316	626	633	3,238
Fuel and purchased power [3]	16,129	3,070	5,237	3,373	4,449
Capital expenditures	1,192	828	275	60	29
Other [4]	310	9	2	2	297
Total	$ 43,663	$ 6,088	$ 7,830	$ 6,721	$ 23,024

(1) Interest on variable-rate debt based on rates as of December 31, 2007.
(2) See Note 6 to the consolidated financial statements.
(3) Amounts under contract with fixed or minimum quantities based on estimated annual requirements.
(4) Includes amounts for capital leases (see Note 6) and contingent tax liabilities (see Note 9).

Guarantees and Other Assurances

As part of normal business activities, we enter into various agreements on behalf of our subsidiaries to provide financial or performance assurances to third parties. These agreements include contract guarantees, surety bonds, and LOCs. Some of the guaranteed contracts contain collateral provisions that are contingent upon our credit ratings.

As of December 31, 2007, our maximum exposure to potential future payments under outstanding guarantees and other assurances approximated $4.5 billion, as summarized below:

Guarantees and Other Assurances		Maximum Exposure
		(In millions)
FirstEnergy Guarantees of Subsidiaries'		
Energy and Energy-Related Contracts [1]	$	503
LOC (long-term debt) – interest coverage [2]		6
Other [3]		503
		1,012
Subsidiaries' Guarantees		
Energy and Energy-Related Contracts		64
LOC (long-term debt) – interest coverage [2]		6
Other [4]		2,641
		2,711
Surety Bonds		73
LOC (long-term debt) – interest coverage [2]		5
LOC (non-debt) [5][6]		692
		770
Total Guarantees and Other Assurances	$	4,493

(1) Issued for open-ended terms, with a 10-day termination right by FirstEnergy.

(2) Reflects the interest coverage portion of LOCs issued in support of floating-rate PCRBs with various maturities. The principal amount of floating-rate PCRBs of $1.6 billion is reflected in debt on FirstEnergy's consolidated balance sheets.

(3) Includes guarantees of $300 million for OVEC obligations and $80 million for nuclear decommissioning funding assurances.

(4) Includes FES' guarantee of FGCO's obligations under the sale and leaseback of Bruce Mansfield Unit 1, but excludes FES' guarantee of FGCO's and NGC's respective obligations under insurance agreements for PCRBs in auction-rate interest mode. The $456 million principal amount of auction-rate PCRBs is reflected in debt on FE's consolidated balance sheets.

(5) Includes $73 million issued for various terms pursuant to LOC capacity available under FirstEnergy's revolving credit facility.

(6) Includes approximately $194 million pledged in connection with the sale and leaseback of Beaver Valley Unit 2 by CEI and TE, $291 million pledged in connection with the sale and leaseback of Beaver Valley Unit 2 by OE and $134 million pledged in connection with the sale and leaseback of Perry Unit 1 by OE.

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

While these types of guarantees are normally parental commitments for the future payment of subsidiary obligations, subsequent to the occurrence of a credit rating downgrade or "material adverse event" the immediate posting of cash collateral or provision of an LOC may be required of the subsidiary. As of December 31, 2007, our maximum exposure under these collateral provisions was $402 million.

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

We have guaranteed the obligations of the operators of the TEBSA project up to a maximum of $6 million (subject to escalation) under the project's operations and maintenance agreement. In connection with the sale of TEBSA in January 2004, the purchaser indemnified us against any loss under this guarantee. We have also provided an LOC ($19 million as of December 31, 2007), which is renewable and declines yearly based upon the senior outstanding debt of TEBSA.

As described above, on July 13, 2007, FGCO completed a sale and leaseback transaction for its 93.825% undivided interest in Bruce Mansfield Unit 1. FES has unconditionally and irrevocably guaranteed all of FGCO's obligations under each of the leases. The related lessor notes and pass through certificates are not guaranteed by FES or FGCO, but the notes are secured by, among other things, each lessor trust's undivided interest in Unit 1, rights and interests under the applicable lease and rights and interests under other related agreements, including FES' lease guaranty.

OFF-BALANCE SHEET ARRANGEMENTS

FES and the Ohio Companies have obligations that are not included on our Consolidated Balance Sheets related to sale and leaseback arrangements involving Perry Unit 1, Beaver Valley Unit 2 and the Bruce Mansfield Plant, which are satisfied through operating lease payments. As of December 31, 2007, the present value of these sale and leaseback operating lease commitments, net of trust investments, total $2.3 billion.

We have equity ownership interests in certain businesses that are accounted for using the equity method of accounting for investments. There are no undisclosed material contingencies related to these investments. Certain guarantees that we do not expect to have a material current or future effect on our financial condition, liquidity or results of operations are disclosed under Guarantees and Other Assurances above.

MARKET RISK INFORMATION

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

Commodity Price Risk

We are exposed to financial and market risks resulting from the fluctuation of interest rates and commodity prices – electricity, energy transmission, natural gas, coal, nuclear fuel and emission allowances. 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 tables below. Contracts that are not exempt from such treatment include certain power purchase agreements with NUG entities that were structured pursuant to the Public Utility Regulatory Policies 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 2007 is summarized in the following table:

Increase (Decrease) in the Fair Value of Derivative Contracts	**Non-Hedge**	**Hedge**	**Total**
		(In millions)	
Change in the Fair Value of Commodity Derivative Contracts:			
Outstanding net liability as of January 1, 2007	$ (1,140)	$ (17)	$ (1,157)
Additions/change in value of existing contracts	117	(21)	96
Settled contracts	310	12	322
Outstanding net liability as of December 31, 2007[1]	$ (713)	$ (26)	$ (739)
Non-commodity Net Liabilities as of December 31, 2007:			
Interest rate swaps[2]	-	(5)	(5)
Net Liabilities - Derivative Contracts as of December 31, 2007	$ (713)	$ (31)	$ (744)
Impact of Changes in Commodity Derivative Contracts[3]			
Income Statement effects (pre-tax)	$ 4	$ -	$ 4
Balance Sheet effects:			
OCI (pre-tax)	$ -	$ (9)	$ (9)
Regulatory asset (net)	$ (423)	$ -	$ (423)

(1) Includes $713 million in non-hedge commodity derivative contracts (primarily with NUGs), which are offset by a regulatory asset.
(2) Interest rate swaps are treated as cash flow or fair value hedges (see "Interest Rate Swap Agreements" below).
(3) 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, 2007 as follows:

Balance Sheet Classification	Non-Hedge	Hedge	Total
		(In millions)	
Current-			
Other assets	$ -	$ 24	$ 24
Other liabilities	-	(48)	(48)
Non-Current-			
Other deferred charges	37	8	45
Other noncurrent liabilities	(750)	(15)	(765)
Net liabilities	$ (713)	$ (31)	$ (744)

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, 2007 are summarized by year in the following table:

Source of Information - Fair Value by Contract Year	2008	2009	2010	2011	2012	Thereafter	Total
				(In millions)			
Prices actively quoted[1]	$ (1)	$ -	$ -	$ -	$ -	$ -	$ (1)
Other external sources[2]	(235)	(172)	(151)	(97)	-	-	(655)
Prices based on models	-	-	-	-	(28)	(55)	(83)
Total[3]	$ (236)	$ (172)	$ (151)	$ (97)	$ (28)	$ (55)	$ (739)

(1) Exchange traded.
(2) Broker quote sheets.
(3) Includes $713 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 (an increase or decrease depending on the derivative position) in quoted market prices in the near term on our derivative instruments would not have had a material effect on our consolidated financial position (assets, liabilities and equity) or cash flows as of December 31, 2007. Based on derivative contracts held as of December 31, 2007, an adverse 10% change in commodity prices would decrease net income by approximately $3 million for the next twelve months.

Interest Rate Risk

Our exposure to fluctuations in market interest rates is reduced since a significant portion of our debt has fixed interest rates, as noted in the table below.

Comparison of Carrying Value to Fair Value

Year of Maturity	2008	2009	2010	2011	2012	There-after	Total	Fair Value
				(Dollars in millions)				
Assets								
Investments other than Cash and Cash Equivalents-Fixed Income	$ 86	$ 64	$ 80	$ 86	$ 103	$ 1,474	$ 1,893	$ 1,988
Average interest rate	6.6%	7.9%	7.9%	7.9%	7.9%	5.6%	6.0%	
Liabilities								
Long-term Debt and Other Long-term Obligations:								
Fixed rate[1]	$ 334	$ 287	$ 199	$ 1,540	$ 43	$ 6,265	$ 8,668	$ 8,908
Average interest rate	5.2%	6.7%	5.4%	6.4%	5.9%	6.3%	6.3%	
Variable rate[1]						$ 2,223	$ 2,223	$ 2,223
Average interest rate						3.7%	3.7%	
Short-term Borrowings	$ 903						$ 903	$ 903
Average interest rate	5.4%						5.4%	

(1) Balances and rates do not reflect the fixed-to-floating interest rate swap agreements discussed below.

We are subject to the inherent interest rate risks related to refinancing maturing debt by issuing new debt securities. As discussed in Note 6 to the consolidated financial statements, our investments in capital trusts effectively reduce future lease obligations, also reducing interest rate risk. Fluctuations in the fair value of NGC's and our Ohio Companies' decommissioning trust balances will eventually affect earnings (immediately for unrealized losses and affecting OCI initially for unrealized gains) based on the guidance in SFAS 115, FSP SFAS 115-1 and SFAS 124-1. The Pennsylvania Companies and JCP&L, however, will either recover or refund to customers the difference between the investments held in trust and their decommissioning obligations. Therefore, there is not expected to be an earnings effect from fluctuations in their decommissioning trust balances. As of December 31, 2007, our decommissioning trust balances totaled $2.1 billion, with $1.5 billion held by NGC and our Ohio Companies and the remaining balance held by JCP&L, Met-Ed and Penelec. The trust balances of NGC and our Ohio Companies were comprised of 66% equity securities and 34% debt instruments as of December 31, 2007.

Interest Rate Swap Agreements - Fair Value Hedges

We utilize fixed-for-floating interest rate swap agreements as part of our ongoing effort to manage the interest rate risk associated with our debt portfolio. These derivatives are treated as fair value hedges of fixed-rate, long-term debt issues – protecting against the risk of changes in the fair value of fixed-rate debt instruments due to lower interest rates. Swap maturities, call options, fixed interest rates and interest payment dates match those of the underlying obligations. During 2007, we paid $2 million to terminate swaps with a notional amount $500 million as our subsidiary redeemed the associated hedged debt. The net loss was recognized as interest expense during 2007. As of December 31, 2007, the debt underlying the $250 million outstanding notional amount of interest rate swaps had a weighted average fixed interest rate of 4.87%, which the swaps have converted to a current weighted average variable rate of 5.48%.

	December 31, 2007			December 31, 2006		
Interest Rate Swaps	**Notional Amount**	**Maturity Date**	**Fair Value**	**Notional Amount**	**Maturity Date**	**Fair Value**
			(In millions)			
Fair value hedges	$ 100	2008	$ -	$ 100	2008	$ (2)
		2010		50	2010	(1)
		2013		300	2013	(6)
	150	2015	(3)	150	2015	(10)
		2025		50	2025	(2)
		2031		100	2031	(6)
	$ 250		$ (3)	$ 750		$ (27)

Forward Starting Swap Agreements - Cash Flow Hedges

We utilize forward starting swap agreements (forward swaps) in order to hedge a portion of the consolidated interest rate risk associated with anticipated future issuances of fixed-rate, long-term debt securities for one or more of our consolidated subsidiaries in 2007 and 2008. These derivatives are treated as cash flow hedges, protecting against the risk of changes in future interest payments resulting from changes in benchmark U.S. Treasury rates between the date of hedge inception and the date of the debt issuance. During 2007, we terminated forward swaps with an aggregate notional value of $2.5 billion at a cost of $30 million. The ineffective portion of that loss ($1.6 million) was recognized in current period earnings. The remaining effective portion of the loss will be recognized over the terms of the associated future debt. As of December 31, 2007, we had outstanding forward swaps with an aggregate notional amount of $400 million and an aggregate fair value of $(3) million.

	December 31, 2007			December 31, 2006		
Forward Starting Swaps	**Notional Amount**	**Maturity Date**	**Fair Value**	**Notional Amount**	**Maturity Date**	**Fair Value**
			(In millions)			
Cash flow hedges	$ 25	2015	$ (1)	$ 25	2015	$ -
		2017		200	2017	(4)
	325	2018	(1)	25	2018	(1)
	50	2020	(1)	50	2020	1
	$ 400		$ (3)	$ 300		$ (4)

Equity Price Risk

Included in nuclear decommissioning trusts are marketable equity securities carried at their current fair value of approximately $1.4 billion as of December 31, 2007. A hypothetical 10% decrease in prices quoted by stock exchanges would result in a $136 million reduction in fair value as of December 31, 2007 (see Note 5(B)).

Certain investments within our nuclear decommissioning, pension and other postretirement benefit trusts hold credit market securities, including subprime mortgage-related assets. The fair value of these subprime-related investments has declined as a result of recent market developments, including a series of rating agency downgrades of subprime mortgage-related assets. We expect that market conditions will continue to evolve, and that the fair value of these investments may frequently change. We have assessed our investments and believe that declines in the fair value of our nuclear decommissioning and pension trusts, due to their relatively small exposure to subprime assets, will not be material.

CREDIT RISK

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

We maintain credit policies with respect to our counterparties to manage overall credit risk. This includes performing independent risk evaluations, actively monitoring portfolio trends and using collateral and contract provisions to mitigate exposure. As part of our credit program, we aggressively manage the quality of our portfolio of energy contracts, evidenced by a current weighted average risk rating for energy contract counterparties of BBB+ (S&P). As of December 31, 2007, the largest credit concentration with one party, JP Morgan (currently rated investment grade), represented 10.7% of our total credit risk. Within our unregulated energy subsidiaries, 99% of credit exposures, net of collateral and reserves, were with investment grade counterparties as of December 31, 2007.

REGULATORY MATTERS

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

- restructuring the electric generation business and allowing the Companies' customers to select competitive electric generation suppliers other than the Companies;
- establishing or defining the PLR obligations to customers in the Companies' service areas;
- providing the Companies with the opportunity to recover potentially stranded investment (or transition costs) not otherwise recoverable in a competitive generation market;
- itemizing (unbundling) the price of electricity into its component elements – including generation, transmission, distribution and stranded costs recovery charges;
- continuing regulation of the Companies' transmission and distribution systems; and
- requiring corporate separation of regulated and unregulated business activities.

The Companies and ATSI recognize, as regulatory assets, costs which the FERC, PUCO, PPUC and 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. Regulatory assets that do not earn a current return totaled approximately $140 million as of December 31, 2007 (JCP&L - $84 million, Met-Ed - $54 million and Penelec - $2 million). Regulatory assets not earning a current return (primarily for certain regulatory transition costs and employee postretirement benefits) will be recovered by 2014 for JCP&L and by 2020 for Met-Ed and Penelec. The following table discloses regulatory assets by company:

Regulatory Assets*	December 31, 2007	December 31, 2006	Increase (Decrease)
		(In millions)	
OE	$ 737	$ 741	$ (4)
CEI	871	855	16
TE	204	248	(44)
JCP&L	1,596	2,152	(556)
Met-Ed	495	409	86
ATSI	42	36	6
Total	$ 3,945	$ 4,441	$ (496)

* Penn had net regulatory liabilities of approximately $67 million and $68 million as of December 31, 2007 and 2006, respectively. Penelec had net regulatory liabilities of approximately $74 million and $96 million as of December 31, 2007 and 2006, respectively. These net regulatory liabilities are included in Other Non-current Liabilities on the Consolidated Balance Sheets.

Regulatory assets by source are as follows:

Regulatory Assets By Source	December 31, 2007	December 31, 2006	Increase (Decrease)
		(In millions)	
Regulatory transition costs	$ 2,363	$ 3,266	$ (903)
Customer shopping incentives	516	603	(87)
Customer receivables for future income taxes	295	217	78
Loss on reacquired debt	57	43	14
Employee postretirement benefits	39	47	(8)
Nuclear decommissioning, decontamination and spent fuel disposal costs	(115)	(145)	30
Asset removal costs	(183)	(168)	(15)
MISO/PJM transmission costs	340	213	127
Fuel costs - RCP	220	113	107
Distribution costs - RCP	321	155	166
Other	92	97	(5)
Total	$ 3,945	$ 4,441	$ (496)

Ohio

The Ohio Companies filed an application and stipulation with the PUCO on September 9, 2005 seeking approval of the RCP, a supplement to the RSP. On November 4, 2005, the Ohio Companies filed a supplemental stipulation with the PUCO, which constituted an additional component of the RCP. On January 4, 2006, the PUCO approved, with modifications, the Ohio Companies' RCP to supplement the RSP to provide customers with more certain rate levels than otherwise available under the RSP during the plan period. The following table provides the estimated net amortization of regulatory transition costs and deferred shopping incentives (including associated carrying charges) under the RCP for the period 2008 through 2010:

Amortization Period	OE	CEI	TE	Total Ohio
		(In millions)		
2008	$ 207	$ 126	$ 113	$ 446
2009	-	212	-	212
2010	-	273	-	273
Total Amortization	$ 207	$ 611	$ 113	$ 931

Several parties subsequently filed appeals to the Supreme Court of Ohio in connection with certain portions of the approved RCP. In its order, the PUCO authorized the Ohio Companies to recover certain increased fuel costs through a fuel rider, and to defer certain other increased fuel costs to be incurred from January 1, 2006 through December 31, 2008, including interest on the deferred balances. The order also provided for recovery of the deferred costs over a 25-year period through distribution rates, which are expected to be effective on January 1, 2009 for OE and TE, and approximately May 2009 for CEI. Through December 31, 2007, the deferred fuel costs, including interest, were $111 million, $76 million and $33 million for OE, CEI and TE, respectively.

On August 29, 2007, the Supreme Court of Ohio concluded that the PUCO violated a provision of the Ohio Revised Code by permitting the Ohio Companies "to collect deferred increased fuel costs through future distribution rate cases, or to alternatively use excess fuel-cost recovery to reduce deferred distribution-related expenses" because fuel costs are a component of generation service, not distribution service, and permitting recovery of deferred fuel costs through distribution rates constituted an impermissible subsidy. The Court remanded the matter to the PUCO for further consideration consistent with the Court's Opinion on this issue and affirmed the PUCO's order in all other respects. On September 10, 2007 the Ohio Companies filed an Application with the PUCO that requested the implementation of two generation-related fuel cost riders to collect the increased fuel costs that were previously authorized to be deferred. The Ohio Companies requested the riders to become effective in October 2007 and end in December 2008, subject to reconciliation that would be expected to continue through the first quarter of 2009. On January 9, 2008 the PUCO approved the Ohio Companies' proposed fuel cost rider to recover increased fuel costs to be incurred commencing January 1, 2008 through December 31, 2008, which is expected to be approximately $167 million. The fuel cost rider became effective January 11, 2008 and will be adjusted and reconciled quarterly. In addition, the PUCO ordered the Ohio Companies to file a separate application for an alternate recovery mechanism to collect the 2006 and 2007 deferred fuel costs. On February 8, 2008, the Ohio Companies filed an application proposing to recover $220 million of deferred fuel costs and carrying charges for 2006 and 2007 pursuant to a separate fuel rider, with alternative options for the recovery period ranging from five to twenty-five years. This second application is currently pending before the PUCO.

The Ohio Companies recover all MISO transmission and ancillary service related costs incurred through a reconcilable rider that is updated annually on July 1. The riders that became effective on July 1, 2007, represent an increase over the amounts collected through the 2006 riders of approximately $64 million annually. If it is subsequently determined by the PUCO that adjustments to the riders as filed are necessary, such adjustments, with carrying costs, will be incorporated into the 2008 transmission rider filing.

The Ohio Companies filed an application and rate request for an increase in electric distribution rates with the PUCO on June 7, 2007. The requested increase is expected to be more than offset by the elimination or reduction of transition charges at the time the rates go into effect and would result in lowering the overall non-generation portion of the average electric bill for most Ohio customers. The distribution rate increases reflect capital expenditures since the Ohio Companies' last distribution rate proceedings, increases in operation and maintenance expenses and recovery of regulatory assets that were authorized in prior cases. On August 6, 2007, the Ohio Companies updated their filing supporting a distribution rate increase of $332 million. On December 4, 2007, the PUCO Staff issued its Staff Reports containing the results of their investigation into the distribution rate request. In its reports, the PUCO Staff recommended a distribution rate increase in the range of $161 million to $180 million, with $108 million to $127 million for distribution revenue increases and $53 million for recovery of costs deferred under prior cases. This amount excludes the recovery of deferred fuel costs, whose recovery is now being sought in a separate proceeding before the PUCO, discussed above. On January 3, 2008, the Ohio Companies and intervening parties filed objections to the Staff Reports and on January 10, 2008, the Ohio Companies filed supplemental testimony. Evidentiary hearings began on January 29, 2008 and continued through February 2008. During the evidentiary hearings, the PUCO Staff submitted testimony decreasing their recommended revenue increase to a range of $114 million to $132 million. Additionally, in testimony submitted on February 11, 2008, the PUCO Staff adopted a position regarding interest deferred pursuant to the RCP that, if upheld by the PUCO, would result in the write-off of approximately $13 million of interest costs deferred through December 31, 2007 ($0.03 per share of common stock). The PUCO is expected to render its decision during the second or third quarter of 2008. The new rates would become effective January 1, 2009 for OE and TE, and approximately May 2009 for CEI.

On July 10, 2007, the Ohio Companies filed an application with the PUCO requesting approval of a comprehensive supply plan for providing retail generation service to customers who do not purchase electricity from an alternative supplier, beginning January 1, 2009. The proposed competitive bidding process would average the results of multiple bidding sessions conducted at different times during the year. The final price per kilowatt-hour would reflect an average of the prices resulting from all bids. In their filing, the Ohio Companies offered two alternatives for structuring the bids, either by customer class or a "slice-of-system" approach. A slice-of-system approach would require the successful bidder to be responsible for supplying a fixed percentage of the utility's total load notwithstanding the customer's classification. The proposal provides the PUCO with an option to phase in generation price increases for residential tariff groups who would experience a change in their average total price of 15 percent or more. The PUCO held a technical conference on August 16, 2007 regarding the filing. Initial and reply comments on the proposal were filed by various parties in September and October, 2007, respectively. The proposal is currently pending before the PUCO.

On September 25, 2007, the Ohio Governor's proposed energy plan was officially introduced into the Ohio Senate. The bill proposes to revise state energy policy to address electric generation pricing after 2008, establish advanced energy portfolio standards and energy efficiency standards, and create GHG emissions reporting and carbon control planning requirements. The bill also proposes to move to a "hybrid" system for determining rates for default service in which electric utilities would provide regulated generation service unless they satisfy a statutory burden to demonstrate the existence of a competitive market for retail electricity. The Senate Energy & Public Utilities Committee conducted hearings on the bill and received testimony from interested parties, including the Governor's Energy Advisor, the Chairman of the PUCO, consumer groups, utility executives and others. Several proposed amendments to the bill were submitted, including those from Ohio's investor-owned electric utilities. A substitute version of the bill, which incorporated certain of the proposed amendments, was introduced into the Senate Energy & Public Utilities Committee on October 25, 2007 and was passed by the Ohio Senate on October 31, 2007. The bill as passed by the Senate is now being considered by the House Public Utilities Committee, which has conducted hearings on the bill. Testimony has been received from interested parties, including the Chairman of the PUCO, consumer groups, utility executives and others. At this time, we cannot predict the outcome of this process nor determine the impact, if any, such legislation may have on our operations or those of the Ohio Companies.

Pennsylvania

Met-Ed and Penelec have been purchasing a portion of their PLR and default service requirements from FES through a partial requirements wholesale power sales agreement and various amendments. Based on the outcome of the 2006 comprehensive transition rate filing, as described below, Met-Ed, Penelec and FES agreed to restate the partial requirements power sales agreement effective January 1, 2007. The restated agreement incorporates the same fixed price for residual capacity and energy supplied by FES as in the prior arrangements between the parties, and automatically extends for successive one year terms unless any party gives 60 days' notice prior to the end of the year. The restated agreement also allows Met-Ed and Penelec to sell the output of NUG energy to the market and requires FES to provide energy at fixed prices to replace any NUG energy sold to the extent needed for Met-Ed and Penelec to satisfy their PLR and default service obligations. The fixed price under the restated agreement is expected to remain below wholesale market prices during the term of the agreement.

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

Met-Ed and Penelec made a comprehensive transition rate filing with the PPUC on April 10, 2006 to address a number of transmission, distribution and supply issues. If Met-Ed's and Penelec's preferred approach involving accounting deferrals had been approved, annual revenues would have increased by $216 million and $157 million, respectively. That filing included, among other things, a request to charge customers for an increasing amount of market-priced power procured through a CBP as the amount of supply provided under the then existing FES agreement was to be phased out. Met-Ed and Penelec also requested approval of a January 12, 2005 petition for the deferral of transmission-related costs incurred during 2006. In this rate filing, Met-Ed and Penelec requested recovery of annual transmission and related costs incurred on or after January 1, 2007, plus the amortized portion of 2006 costs over a ten-year period, along with applicable carrying charges, through an adjustable rider. Changes in the recovery of NUG expenses and the recovery of Met-Ed's non-NUG stranded costs were also included in the filing. On May 4, 2006, the PPUC consolidated the remand of the FirstEnergy and GPU merger proceeding, related to the quantification and allocation of merger savings, with the comprehensive transition rate filing case.

The PPUC entered its opinion and order in the comprehensive rate filing proceeding on January 11, 2007. The order approved the recovery of transmission costs, including the transmission-related deferral for January 1, 2006 through January 10, 2007, and determined that no merger savings from prior years should be considered in determining customers' rates. The request for increases in generation supply rates was denied as were the requested changes to NUG expense recovery and Met-Ed's non-NUG stranded costs. The order decreased Met-Ed's and Penelec's distribution rates by $80 million and $19 million, respectively. These decreases were offset by the increases allowed for the recovery of transmission costs. Met-Ed's and Penelec's request for recovery of Saxton decommissioning costs was granted and, in January 2007, Met-Ed and Penelec recognized income of $15 million and $12 million, respectively, to establish regulatory assets for those previously expensed decommissioning costs. Overall rates increased by 5.0% for Met-Ed ($59 million) and 4.5% for Penelec ($50 million). Met-Ed and Penelec filed a Petition for Reconsideration on January 26, 2007, on the issues of consolidated tax savings and rate of return on equity. Other parties filed Petitions for Reconsideration on transmission (including congestion), transmission deferrals and rate design issues. On March 1, 2007, the PPUC issued three orders: (1) a tentative order regarding the reconsideration by the PPUC of its own order; (2) an order denying the Petitions for Reconsideration of Met-Ed, Penelec and the OCA and denying in part and accepting in part the MEIUG's and PICA's Petition for Reconsideration; and (3) an order approving the compliance filing. Comments to the PPUC for reconsideration of its order were filed on March 8, 2007, and the PPUC ruled on the reconsideration on April 13, 2007, making minor changes to rate design as agreed upon by Met-Ed, Penelec and certain other parties.

On March 30, 2007, MEIUG and PICA filed a Petition for Review with the Commonwealth Court of Pennsylvania asking the court to review the PPUC's determination on transmission (including congestion) and the transmission deferral. Met-Ed and Penelec filed a Petition for Review on April 13, 2007 on the issues of consolidated tax savings and the requested generation rate increase. The OCA filed its Petition for Review on April 13, 2007, on the issues of transmission (including congestion) and recovery of universal service costs from only the residential rate class. From June through October 2007, initial responsive and reply briefs were filed by various parties. Oral arguments are expected to take place on April 7, 2008. If Met-Ed and Penelec do not prevail on the issue of congestion, it could have a material adverse effect on our results of operations and those of Met-Ed and Penelec.

As of December 31, 2007, Met-Ed's and Penelec's unrecovered regulatory deferrals pursuant to the 2006 comprehensive transition rate case, the 1998 Restructuring Settlement (including the Phase 2 proceedings) and the FirstEnergy/GPU Merger Settlement Stipulation were $512 million and $55 million, respectively. During the PPUC's annual audit of Met-Ed's and Penelec's NUG stranded cost balances in 2006, it noted a modification to the NUG purchased power stranded cost accounting methodology made by Met-Ed and Penelec. On August 18, 2006, a PPUC order was entered requiring Met-Ed and Penelec to reflect the deferred NUG cost balances as if the stranded cost accounting methodology modification had not been implemented. As a result of this PPUC order, Met-Ed recognized a pre-tax charge of approximately $10.3 million in the third quarter of 2006, representing incremental costs deferred under the revised methodology in 2005. Met-Ed and Penelec continue to believe that the stranded cost accounting methodology modification is appropriate and on August 24, 2006 filed a petition with the PPUC pursuant to its order for authorization to reflect the stranded cost accounting methodology modification effective January 1, 1999. Hearings on this petition were held in February 2007 and briefing was completed on March 28, 2007. The ALJ's initial decision denied Met-Ed's and Penelec's request to modify their NUG stranded cost accounting methodology. The companies filed exceptions to the initial decision on May 23, 2007 and replies to those exceptions were filed on June 4, 2007. On November 8, 2007, the PPUC issued an order denying any changes in the accounting methodology for NUGs.

On May 2, 2007, Penn filed a plan with the PPUC for the procurement of default service supply from June 2008 through May 2011. The filing proposed multiple, competitive RFPs with staggered delivery periods for fixed-price, tranche-based, pay as bid default service supply to the residential and commercial classes. The proposal would phase out existing promotional rates and eliminates the declining block and the demand components on generation rates for residential and commercial customers. The industrial class default service would be provided through an hourly-priced service provided by Penn. Quarterly reconciliation of the differences between the costs of supply and revenues from customers was also proposed. On September 28, 2007, Penn filed a Joint Petition for Settlement resolving all but one issue in the case. Briefs were also filed on September 28, 2007 on the unresolved issue of incremental uncollectible accounts expense. The settlement was either supported, or not opposed, by all parties. On December 20, 2007, the PPUC approved the settlement except for the full requirements tranche approach for residential customers, which was remanded to the ALJ for hearings. Under the terms of the Settlement Agreement, the default service procurement for small commercial customers will be done with multiple RFPs, while the default service procurement for large commercial and industrial customers will utilize hourly pricing. Bids in the first RFP for small commercial load were received on February 20, 2008. In February 2008, parties filed direct and rebuttal testimony in the remand proceeding for the residential procurement approach. An evidentiary hearing was held on February 26, 2008, and this matter will be presented to the PPUC for its consideration by March 13, 2008.

On February 1, 2007, the Governor of Pennsylvania proposed an EIS. The EIS includes four pieces of proposed legislation that, according to the Governor, is designed to reduce energy costs, promote energy independence and stimulate the economy. Elements of the EIS include the installation of smart meters, funding for solar panels on residences and small businesses, conservation and demand reduction programs to meet energy growth, a requirement that electric distribution companies acquire power that results in the "lowest reasonable rate on a long-term basis," the utilization of micro-grids and a three year phase-in of rate increases. On July 17, 2007 the Governor signed into law two pieces of energy legislation. The first amended the Alternative Energy Portfolio Standards Act of 2004 to, among other things, increase the percentage of solar energy that must be supplied at the conclusion of an electric distribution company's transition period. The second law allows electric distribution companies, at their sole discretion, to enter into long term contracts with large customers and to build or acquire interests in electric generation facilities specifically to supply long-term contracts with such customers. A special legislative session on energy was convened in mid-September 2007 to consider other aspects of the EIS. On December 12, 2007, the Pennsylvania Senate passed the Alternative Energy Investment Act which, as amended, provides over $650 million over ten years to implement the Governor's proposal. The bill was then referred to the House Environmental Resources and Energy Committee where it awaits consideration. On February 12, 2008, the Pennsylvania House passed House Bill 2200 which provides for energy efficiency and demand management programs and targets as well as the installation of smart meters within ten years. Other legislation has been introduced to address generation procurement, expiration of rate caps, conservation and renewable energy. The final form of this pending legislation is uncertain. Consequently, we are unable to predict what impact, if any, such legislation may have on our operations.

New Jersey

JCP&L is permitted to defer for future collection from customers the amounts by which its costs of supplying BGS to non-shopping customers and costs incurred under NUG agreements exceed amounts collected through BGS and NUGC rates and market sales of NUG energy and capacity. As of December 31, 2007, the accumulated deferred cost balance totaled approximately $322 million.

In accordance with an April 28, 2004 NJBPU order, JCP&L filed testimony on June 7, 2004 supporting 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, JCP&L 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, JCP&L filed a response to those 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 the PUHCA pursuant to the EPACT. The NJBPU approved regulations effective October 2, 2006 that 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 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. The NJBPU Staff circulated revised drafts of the proposal to interested stakeholders in November 2006 and again in February 2007. On February 1, 2008, the NJBPU accepted proposed rules for publication in the New Jersey Register on March 17, 2008. An April 23, 2008 public hearing on these proposed rules is expected to be scheduled with comments from interested parties expected to be due on May 17, 2008.

New Jersey statutes require that the state periodically undertake a planning process, known as the 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 New Jersey'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;
- Maintain unit prices for electricity to 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 obtain input from a broad range of interested stakeholders including utilities, environmental groups, customer groups, and major customers. EMP working groups addressing: (1) energy efficiency and demand response; (2) renewables; (3) reliability; and (4) pricing issues, have completed their assigned tasks of data gathering and analysis and have provided reports to the EMP Committee. Public stakeholder meetings were held in the fall of 2006 and in early 2007, and further public meetings are expected in 2008. At this time, we cannot predict the outcome of this process nor determine the impact, if any, such legislation may have on our operations or those of JCP&L.

On February 13, 2007, the NJBPU Staff informally issued a draft proposal relating to changes to the regulations addressing electric distribution service reliability and quality standards. Meetings between the NJBPU Staff and interested stakeholders to discuss the proposal were held and additional, revised informal proposals were subsequently circulated by the Staff. On September 4, 2007, proposed regulations were published in the New Jersey Register, which proposal will be subsequently considered by the NJBPU following comments that were submitted in September and October 2007. At this time, we cannot predict the outcome of this process nor determine the impact, if any, such regulations may have on our operations or those of JCP&L.

FERC Matters

Transmission Service between MISO and PJM

On November 18, 2004, the FERC issued an order eliminating the through and out rate for transmission service between the MISO and PJM regions. FERC's intent was to eliminate so-called "pancaking" of transmission charges 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 rate mechanism to recover lost transmission revenues created by elimination of this charge (referred to as the Seams Elimination Cost Adjustment or "SECA") during a 16-month transition period. The FERC issued orders in 2005 setting the SECA for hearing. The presiding judge issued an initial decision on August 10, 2006, rejecting the compliance filings made by MISO, PJM, and the transmission owners, 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 the first quarter of 2008.

PJM Transmission Rate Design

On January 31, 2005, certain PJM transmission owners made filings with the FERC pursuant to a settlement agreement previously approved by the FERC. JCP&L, 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. Hearings were held and numerous parties appeared and litigated various issues concerning PJM rate design; notably AEP, which proposed to create a "postage stamp", or average rate for all high voltage transmission facilities across PJM and a zonal transmission rate for facilities below 345 kV. This proposal would have the effect of shifting recovery of the costs of high voltage transmission lines to other transmission zones, including those where JCP&L, Met-Ed, and Penelec serve load. The ALJ issued an initial decision directing that the cost of all PJM transmission facilities, regardless of voltage, should be recovered through a postage stamp rate. The ALJ recommended an April 1, 2006 effective date for this change in rate design. Numerous parties, including us, submitted briefs opposing the ALJ's decision and recommendations. On April 19, 2007, the FERC issued an order rejecting the ALJ's findings and recommendations in nearly every respect. The FERC found that the PJM transmission owners' existing "license plate" or zonal rate design was just and reasonable and ordered that the current license plate rates for existing transmission facilities be retained. On the issue of rates for new transmission facilities, the FERC directed that costs for new transmission facilities that are rated at 500 kV or higher are to be collected from all transmission zones throughout the PJM footprint by means of a postage-stamp rate. Costs for new transmission facilities that are rated at less than 500 kV, however, are to be allocated on a "beneficiary pays" basis. FERC found that PJM's current beneficiary-pays cost allocation methodology is not sufficiently detailed and, in a related order that also was issued on April 19, 2007, directed that hearings be held for the purpose of establishing a just and reasonable cost allocation methodology for inclusion in PJM's tariff.

On May 18, 2007, certain parties filed for rehearing of the FERC's April 19, 2007 order. On January 31, 2008, the requests for rehearing were denied. The FERC's orders on PJM rate design will prevent the allocation of a portion of the revenue requirement of existing transmission facilities of other utilities to JCP&L, Met-Ed and Penelec. In addition, the FERC's decision to allocate the cost of new 500 kV and above transmission facilities on a PJM-wide basis will reduce future transmission revenue recovery from the JCP&L, Met-Ed and Penelec zones. A partial settlement agreement addressing the "beneficiary pays" methodology for below 500 kV facilities, but excluding the issue of allocating new facilities costs to merchant transmission entities, was filed on September 14, 2007. The agreement was supported by the FERC's Trial Staff, and was certified by the Presiding Judge. The FERC's action on the settlement agreement is pending. The remaining merchant transmission cost allocation issues will proceed to hearing in May 2008. On February 13, 2008, AEP appealed the FERC's orders to the federal Court of Appeals for the D.C. Circuit. The Illinois Commerce Commission has also appealed these orders.

Post Transition Period Rate Design

FERC had directed MISO, PJM, and the respective transmission owners to make filings on or before August 1, 2007 to reevaluate transmission rate design within the MISO, and between MISO and PJM. On August 1, 2007, filings were made by MISO, PJM, and the vast majority of transmission owners, including FirstEnergy affiliates, which proposed to retain the existing transmission rate design. These filings were approved by the FERC on January 31, 2008. As a result of FERC's approval, the rates charged to our load-serving affiliates for transmission service over existing transmission facilities in MISO and PJM are unchanged. In a related filing, MISO and MISO transmission owners requested that the current MISO pricing for new transmission facilities that spreads 20% of the cost of new 345 kV and higher transmission facilities across the entire MISO footprint (known as the Regional Expansion Criteria & Benefits (RECB) methodology) be retained.

Certain stand-alone transmission companies in MISO made a filing under Section 205 of the Federal Power Act requesting that 100% of the cost of new qualifying 345 kV and higher transmission facilities be spread throughout the entire MISO footprint. Further, Indianapolis Power and Light Company separately moved the FERC to reopen the record to address the cost allocation under the RECB methodology. FERC rejected these requests in an order issued January 31, 2008 again maintaining the status quo with respect to allocation of the cost of new transmission facilities in the MISO.

On September 17, 2007, AEP filed a complaint under Sections 206 and 306 of the Federal Power Act seeking to have the entire transmission rate design and cost allocation methods used by MISO and PJM declared unjust, unreasonable, and unduly discriminatory, and to have FERC fix a uniform regional transmission rate design and cost allocation method for the entire MISO and PJM "SuperRegion" that recovers the average cost of new and existing transmission facilities operated at voltages of 345 kV and above from all transmission customers. Lower voltage facilities would continue to be recovered in the local utility transmission rate zone through a license plate rate. AEP requested a refund effective October 1, 2007, or alternatively, February 1, 2008. On January 31, 2008, FERC issued an order denying the complaint.

Distribution of MISO Network Service Revenues

Effective February 1, 2008, the MISO Transmission Owners Agreement provides for a change in the method of distributing transmission revenues among the transmission owners. MISO and a majority of the MISO transmission owners, including ATSI, filed on December 3, 2007 to change the MISO tariff to clarify, for purposes of distributing network transmission revenue to the transmission owners, that all network transmission service revenues, whether collected by MISO or directly by the transmission owner, are included in the revenue distribution calculation. This clarification was necessary because some network transmission service revenues are collected and retained by transmission owners in states where retail choice does not exist, and their "unbundled" retail load is currently exempt from MISO network service charges. The tariff changes filed with FERC ensure that revenues collected by transmission owners from bundled load are taken into account in the revenue distribution calculation, and that transmission owners with bundled load do not collect more than their revenue requirements. Absent the changes, transmission owners, and ultimately their customers, with unbundled load or in retail choice states, such as ATSI, would subsidize transmission owners with bundled load, who would collect their revenue requirement from bundled load, plus share in revenues collected by MISO from unbundled customers. This would result in a significant revenue shortfall for ATSI, which would eventually be passed on to customers in the form of higher transmission rates as calculated pursuant to ATSI's Attachment O formula under the MISO tariff.

Numerous parties filed in support of the tariff changes, including the public service commissions of Michigan, Ohio and Wisconsin. Ameren filed a protest on December 26, 2007, arguing that the December 3 filing violates the MISO Transmission Owners' Agreement as well as an agreement among Ameren (Union Electric), MISO, and the Missouri Public Service Commission, which provides that Union Electric's bundled load cannot be charged by MISO for network service. On January 31, 2008, FERC issued an order conditionally accepting the tariff amendment subject to a minor compliance filing. This order ensures that ATSI's transmission revenues from MISO will continue to be equivalent to its transmission revenue requirement and therefore it will not suffer any revenue shortfall.

MISO Ancillary Services Market and Balancing Area Consolidation

MISO made a filing on September 14, 2007 to establish Ancillary Services markets for regulation, spinning and supplemental reserves, to consolidate the existing 24 balancing areas within the MISO footprint, and to establish MISO as the NERC registered balancing authority for the region. This filing would permit load serving entities to purchase their operating reserve requirements in a competitive market. An effective date of June 1, 2008 was requested in the filing.

MISO's previous filing to establish an Ancillary Services market was rejected without prejudice by FERC on June 22, 2007, subject to MISO providing an analysis of market power within its footprint and a plan to ensure reliability during the consolidation of balancing areas. MISO made a September 14 filing addressing the FERC's directives. FirstEnergy supports the proposal to establish markets for Ancillary Services and consolidate existing balancing areas, but filed objections on specific aspects of the MISO proposal. Interventions and protests to MISO's filing were made with FERC on October 15, 2007. FERC conducted a technical conference so that the MISO independent market monitor could address market power questions about the MISO proposal on December 6, 2007, and additional comments were filed by us and other parties on December 19, 2007. FERC action is anticipated in the first quarter of 2008.

Duquesne's Request to Withdraw from PJM

On November 8, 2007, Duquesne Light Company (Duquesne) filed a request with the FERC to exit PJM and to join the MISO. In its filing, Duquesne asked FERC to be relieved of certain capacity payment obligations to PJM for capacity auctions conducted prior to its departure from PJM, but covering service for planning periods through May 31, 2010. Duquesne asserted that its primary reason for exiting PJM is to avoid paying future obligations created by PJM's forward capacity market. We believe that Duquesne's filing did not identify or address numerous legal, financial or operational issues that we believe are implicated or affected directly by Duquesne's proposal. Consequently, on December 4, 2007 and January 3, 2008, we submitted responsive filings that, while conceding Duquesne's rights to exit PJM, contested various aspects of Duquesne's proposal. We particularly focused on Duquesne's proposal that it be allowed to exit PJM without payment of its share of existing capacity market commitments. We also objected to Duquesne's failure to address the firm transmission service requirements that would be necessary for FirstEnergy to continue to use the Beaver Valley Plant to meet existing commitments in the PJM capacity markets and to serve native load. Additionally, we protested Duquesne's failure to identify or address a number of legal, financial or operational issues and uncertainties that may or will result for both PJM and MISO market participants. Other market participants also submitted filings contesting Duquesne's plans.

On January 17, 2008, the FERC conditionally approved Duquesne's request to exit PJM. Among other conditions, FERC obligated Duquesne to pay the PJM capacity obligations that had accrued prior to January 17, 2008. Duquesne was given until February 1, 2008 to provide FERC written notice of its intent to withdraw and Duquesne filed the notice on February 1st. The FERC's order took notice of the numerous transmission and other issues raised by FirstEnergy and other parties to the proceeding, but did not provide any responsive rulings or other guidance. Rather, FERC ordered Duquesne to make a compliance filing in forty-five days from the FERC order (or by March 3, 2008) detailing how Duquesne will satisfy its obligations under the PJM Transmission Owners' Agreement. The FERC likewise directed the MISO to submit a compliance filing in forty-five days (or by March 3, 2008) detailing the MISO's plans to integrate Duquesne into the MISO. Finally, the FERC directed MISO and PJM to work together to resolve the substantive and procedural issues implicated by Duquesne's transition into the MISO. On February 19, 2008, we asked for clarification or rehearing of certain of the matters addressed in FERC's January 17, 2008 Order.

MISO Resource Adequacy Proposal

MISO made a filing on December 28, 2007 that would create an enforceable planning reserve requirement in the MISO tariff for load serving entities such as the Ohio Companies, Penn, and FES. This requirement is proposed to become effective for the planning year beginning June 1, 2009. The filing would permit MISO to establish the reserve margin requirement for load serving entities based upon a one day loss of load in ten years standard, unless the state utility regulatory agency establishes a different planning reserve for load serving entities in its state. We generally support the proposal as it promotes a mechanism that will result in long-term commitments from both load-serving entities and resources, including both generation and demand side resources that are necessary for reliable resource adequacy and planning in the MISO footprint. We do not expect this filing to impose additional supply costs since our load serving entities in MISO are already bound by similar planning reserve requirements established by *ReliabilityFirst* Corporation. Comments on the filing were filed on January 28, 2008. An effective date of June 1, 2009 was requested in the filing, but MISO has requested FERC approval by the end of the first quarter of 2008.

Organized Wholesale Power Markets

On February 21, 2008, the FERC issued a NOPR through which it proposes to adopt new rules that it states will "improve operations in organized electric markets, boost competition and bring additional benefits to consumers." The proposed rule addresses demand response and market pricing during reserve shortages, long-term power contracting, market-monitoring policies, and responsiveness of RTOs and ISOs to stakeholders and customers. We have not yet had an opportunity to evaluate the impact of the proposed rule on our operations.

Reliability Initiatives

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. The proposed enhancements were divided into two groups: enhancements that were to be completed in 2004; and enhancements that were to be completed after 2004. In 2004, we completed all of the enhancements that were recommended for completion in 2004. Subsequently, we have worked systematically to complete all of the enhancements that were identified for completion after 2004, and we expect to complete this work prior to the summer of 2008. The FERC and the other affected government agencies and reliability entities may review our work and, on the basis of any such review, may recommend additional enhancements in the future, which could require additional, material expenditures.

As a result of outages experienced in JCP&L's service area in 2002 and 2003, the NJBPU performed a review of JCP&L's service reliability. On June 9, 2004, the NJBPU approved a stipulation that addresses a third-party consultant's recommendations on appropriate courses of action necessary to ensure system-wide reliability. The stipulation incorporates the consultant's focused audit of, and recommendations regarding, JCP&L's Planning and Operations and Maintenance programs and practices. On June 1, 2005, the consultant completed his work and issued his final report to the NJBPU. On July 14, 2006, JCP&L filed a comprehensive response to the consultant's report with the NJBPU. JCP&L will complete the remaining substantive work described in the stipulation in 2008. JCP&L continues to file compliance reports with the NJBPU reflecting JCP&L's activities associated with implementing the stipulation.

In 2005, Congress amended the Federal Power Act to provide for federally-enforceable mandatory reliability standards. The mandatory reliability standards apply to the bulk power system and impose certain operating, record-keeping and reporting requirements on the Companies and ATSI. The NERC is charged with establishing and enforcing these reliability standards, although it has delegated day-to-day implementation and enforcement of its responsibilities to eight regional entities, including the Reliabilty*First* Corporation. All of our facilities are located within the Reliabilty*First* region. We actively participate in the NERC and Reliabilty*First* stakeholder processes, and otherwise monitor and manage our companies in response to the ongoing development, implementation and enforcement of the reliability standards.

We believe that we are in compliance with all currently-effective and enforceable reliability standards. Nevertheless, it is clear that NERC, Reliabilty*First* and the FERC will continue to refine existing reliability standards as well as to develop and adopt new reliability standards. The financial impact of complying with new or amended standards cannot be determined at this time. However, the 2005 amendments to the Federal Power Act provide that all prudent costs incurred to comply with the new reliability standards be recovered in rates. Still, any future inability on our part to comply with the reliability standards for our bulk power system could have a material adverse effect on our financial condition, results of operations and cash flows.

In April 2007, Reliability*First* performed a routine compliance audit of our bulk-power system within the Midwest ISO region and found us to be in full compliance with all audited reliability standards. Similarly, Reliability*First* has scheduled a compliance audit of our bulk-power system within the PJM region in 2008. We currently do not expect any material adverse financial impact as a result of these audits.

ENVIRONMENTAL MATTERS

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

Clean Air Act Compliance

We are required to meet federally-approved SO_2 emissions regulations. Violations of such regulations can result in the shutdown of the generating unit involved and/or civil or criminal penalties of up to $32,500 for each day the unit is in violation. The EPA has an interim enforcement policy for SO_2 regulations in Ohio that allows for compliance based on a 30-day averaging period. We believe we are currently in compliance with this policy, but cannot predict what action the EPA may take in the future with respect to the interim enforcement policy.

The EPA Region 5 issued a Finding of Violation and NOV to the Bay Shore Power Plant dated June 15, 2006, alleging violations to various sections of the Clean Air Act. We have disputed those alleged violations based on our Clean Air Act permit, the Ohio SIP and other information provided to the EPA at an August 2006 meeting with the EPA. The EPA has several enforcement options (administrative compliance order, administrative penalty order, and/or judicial, civil or criminal action) and has indicated that such option may depend on the time needed to achieve and demonstrate compliance with the rules alleged to have been violated. On June 5, 2007, the EPA requested another meeting to discuss "an appropriate compliance program" and a disagreement regarding the opacity limit applicable to the common stack for Bay Shore Units 2, 3 and 4.

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

On May 22, 2007, we along with FGCO received a notice letter, required 60 days prior to the filing of a citizen suit under the federal Clean Air Act, alleging violations of air pollution laws at the Bruce Mansfield Plant, including opacity limitations. Prior to the receipt of this notice, the Plant was subject to a Consent Order and Agreement with the Pennsylvania Department of Environmental Protection concerning opacity emissions under which efforts to achieve compliance with the applicable laws will continue. On October 16, 2007, PennFuture filed a complaint, joined by three of its members, in the United States District Court for the Western District of Pennsylvania. On January 11, 2008, we filed a motion to dismiss claims alleging a public nuisance. FGCO is not required to respond to other claims until the Court rules on this motion to dismiss.

On December 18, 2007, the state of New Jersey filed a Clean Air Act citizen suit alleging new source review violations at the Portland Generation Station against Reliant (the current owner and operator), Sithe Energy (the purchaser of the Portland Station from Met-Ed in 1999), GPU, Inc. and Met-Ed. Specifically, New Jersey alleges that "modifications" at Portland Units 1 and 2 occurred between 1980 and 1995 without preconstruction new source review or permitting required by the Clean Air Act's prevention of significant deterioration program, and seeks injunctive relief, penalties, attorney fees and mitigation of the harm caused by excess emissions. Although it remains liable for civil or criminal penalties and fines that may be assessed relating to events prior to the sale of the Portland Station in 1999, Met-Ed is indemnified by Sithe Energy against any other liability arising under the CAA whether it arises out of pre-1999 or post-1999 events.

National Ambient Air Quality Standards

In March 2005, the EPA finalized the CAIR covering a total of 28 states (including Michigan, New Jersey, Ohio and Pennsylvania) and the District of Columbia based on proposed findings that air emissions from 28 eastern states and the District of Columbia significantly contribute to non-attainment of the NAAQS for fine particles and/or the "8-hour" ozone NAAQS in other states. CAIR requires reductions of NO_X and SO_2 emissions in two phases (Phase I in 2009 for NO_X, 2010 for SO_2 and Phase II in 2015 for both NO_X and SO_2). Our Michigan, Ohio and Pennsylvania fossil generation facilities will be subject to caps on SO_2 and NO_X emissions, whereas our New Jersey fossil generation facility will be subject to only a cap on NO_X emissions. According to the EPA, SO_2 emissions will be reduced by 45% (from 2003 levels) by 2010 across the states covered by the rule, with reductions reaching 73% (from 2003 levels) by 2015, capping SO_2 emissions in affected states to just 2.5 million tons annually. NO_X emissions will be reduced by 53% (from 2003 levels) by 2009 across the states covered by the rule, with reductions reaching 61% (from 2003 levels) by 2015, achieving a regional NO_X cap of 1.3 million tons annually. CAIR has been challenged in the United States Court of Appeals for the District of Columbia. The future cost of compliance with these regulations may be substantial and may depend on the outcome of this litigation and how CAIR is ultimately implemented.

Mercury Emissions

In December 2000, the EPA announced it would proceed with the development of regulations regarding hazardous air pollutants from electric power plants, identifying mercury as the hazardous air pollutant of greatest concern. In March 2005, the EPA finalized the CAMR, which provides a cap-and-trade program to reduce mercury emissions from coal-fired power plants in two phases; initially, capping national mercury emissions at 38 tons by 2010 (as a "co-benefit" from implementation of SO_2 and NO_X emission caps under the EPA's CAIR program) and 15 tons per year by 2018. Several states and environmental groups appealed CAMR to the United States Court of Appeals for the District of Columbia, which on February 8, 2008, vacated CAMR ruling that the EPA failed to take the necessary steps to "de-list" coal-fired power plants from its hazardous air pollutant program and, therefore, could not promulgate a cap and trade program. The EPA must now seek judicial review of that ruling or take regulatory action to promulgate new mercury emission standards for coal-fired power plants. FGCO's future cost of compliance with mercury regulations may be substantial and will depend on the action taken by the EPA and on how they are ultimately implemented.

Pennsylvania has submitted a new mercury rule for EPA approval that does not provide a cap-and-trade approach as in the CAMR, but rather follows a command-and-control approach imposing emission limits on individual sources. It is anticipated that compliance with these regulations, if approved by the EPA and implemented, would not require the addition of mercury controls at the Bruce Mansfield Plant, our only Pennsylvania coal-fired power plant, until 2015, if at all.

W. H. Sammis Plant

In 1999 and 2000, the EPA issued an NOV and the DOJ filed a civil complaint against OE and Penn based on operation and maintenance of the W.H. Sammis Plant (Sammis NSR Litigation) and filed similar complaints involving 44 other U.S. power plants. This case, along with seven other similar cases, are referred to as the New Source Review (NSR) cases.

On March 18, 2005, OE and Penn announced that they had reached a settlement with the EPA, the DOJ and three states (Connecticut, New Jersey and New York) that resolved all issues related to the Sammis NSR litigation. This settlement agreement, which is in the form of a consent decree, was approved by the court on July 11, 2005, and requires reductions of NO_X and SO_2 emissions at the Sammis, Burger, Eastlake and Mansfield coal-fired plants through the installation of pollution control devices and provides for stipulated penalties for failure to install and operate such pollution controls in accordance with that agreement. Consequently, if we fail to install such pollution control devices, for any reason, including, but not limited to, the failure of any third-party contractor to timely meet its delivery obligations for such devices, we could be exposed to penalties under the Sammis NSR Litigation consent decree. Capital expenditures necessary to complete requirements of the Sammis NSR Litigation consent decree are currently estimated to be $1.3 billion for 2008-2012 ($650 million of which is expected to be spent during 2008, with the largest portion of the remaining $650 million expected to be spent in 2009).

The Sammis NSR Litigation consent decree also requires us to spend up to $25 million toward environmentally beneficial projects, $14 million of which is satisfied by entering into 93 MW (or 23 MW if federal tax credits are not applicable) of wind energy purchased power agreements with a 20-year term. An initial 16 MW of the 93 MW consent decree obligation was satisfied during 2006.

On August 26, 2005, FGCO entered into an agreement with Bechtel Power Corporation, or Bechtel, under which Bechtel will engineer, procure and construct AQC systems for the reduction of SO_2 emissions. FGCO also entered into an agreement with Babcock & Wilcox Company, or B&W, on August 25, 2006 to supply flue gas desulfurization systems for the reduction of SO_2 emissions. SCR systems for the reduction of NO_X emissions are also being installed at the Sammis Plant under a 1999 Agreement with B&W.

On April 2, 2007, the United States Supreme Court ruled that changes in annual emissions (in tons/year) rather than changes in hourly emissions rate (in kilograms/hour) must be used to determine whether an emissions increase triggers NSR. Subsequently, on May 8, 2007, the EPA proposed to change the NSR regulations to utilize changes in the hourly emission rate (in kilograms/hour) to determine whether an emissions increase triggers NSR. The EPA has not yet issued a final regulation. FGCO's future cost of compliance with those regulations may be substantial and will depend on how they are ultimately implemented.

Climate Change

In December 1997, delegates to the United Nations' climate summit in Japan adopted an agreement, the Kyoto Protocol, to address global warming by reducing the amount of man-made GHG emitted by developed countries by 2012. The United States signed the Kyoto Protocol in 1998 but it failed to receive the two-thirds vote required for ratification by the United States Senate. However, the Bush administration has committed the United States to a voluntary climate change strategy to reduce domestic GHG intensity – the ratio of emissions to economic output – by 18% through 2012. In addition, the EPACT established a Committee on Climate Change Technology to coordinate federal climate change activities and promote the development and deployment of GHG reducing technologies.

There are a number of initiatives to reduce GHG emissions under consideration at the federal, state and international level. At the international level, efforts to reach a new global agreement to reduce GHG emissions post-2012 have begun with the Bali Roadmap, which outlines a two-year process designed to lead to an agreement in 2009. At the federal level, members of Congress have introduced several bills seeking to reduce emissions of GHG in the United States, and the Senate Environmental and Public Works Committees have passed one such bill. State activities, primarily the northeastern states participating in the Regional Greenhouse Gas Initiative and western states led by California, have coordinated efforts to develop regional strategies to control emissions of certain GHGs.

On April 2, 2007, the United States Supreme Court found that the EPA has the authority to regulate CO_2 emissions from automobiles as "air pollutants" under the Clean Air Act. Although this decision did not address CO_2 emissions from electric generating plants, the EPA has similar authority under the Clean Air Act to regulate "air pollutants" from those and other facilities.

We cannot currently estimate the financial impact of climate change policies, although potential legislative or regulatory programs restricting CO_2 emissions could require significant capital and other expenditures. The CO_2 emissions per KWH of electricity generated by us is lower than many regional competitors due to our diversified generation sources, which include low or non-CO_2 emitting gas-fired and nuclear generators.

Clean Water Act

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

On September 7, 2004, the EPA established new performance standards under Section 316(b) of the Clean Water Act for reducing impacts on fish and shellfish from cooling water intake structures at certain existing large electric generating plants. The regulations call for reductions in impingement mortality (when aquatic organisms are pinned against screens or other parts of a cooling water intake system) and entrainment (which occurs when aquatic life is drawn into a facility's cooling water system). On January 26, 2007, the United States Court of Appeals for the Second Circuit remanded portions of the rulemaking dealing with impingement mortality and entrainment back to the EPA for further rulemaking and eliminated the restoration option from the EPA's regulations. On July 9, 2007, the EPA suspended this rule, noting that until further rulemaking occurs, permitting authorities should continue the existing practice of applying their best professional judgment (BPJ) to minimize impacts on fish and shellfish from cooling water intake structures. We are evaluating various control options and their costs and effectiveness. Depending on the outcome of such studies, the EPA's further rulemaking and any action taken by the states exercising BPJ, the future cost of compliance with these standards may require material capital expenditures.

Regulation of Hazardous Waste

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

Under NRC regulations, we must ensure that adequate funds will be available to decommission our nuclear facilities. As of December 31, 2007, we had approximately $1.5 billion invested in external trusts to be used for the decommissioning and environmental remediation of Davis-Besse, Beaver Valley and Perry. As part of the application to the NRC to transfer the ownership of these nuclear facilities to NGC in 2005, we agreed to contribute another $80 million to these trusts by 2010. Consistent with NRC guidance, utilizing a "real" rate of return on these funds of approximately 2% over inflation, these trusts are expected to exceed the minimum decommissioning funding requirements set by the NRC. Conservatively, these estimates do not include any rate of return that the trusts may earn over the 20-year plant useful life extensions that we (and Exelon for TMI-1 as it relates to the timing of the decommissioning of TMI-2) seek for these facilities.

The Companies have been named as PRPs at waste disposal sites, which may require cleanup under the Comprehensive Environmental Response, Compensation, and Liability Act of 1980. Allegations of disposal of hazardous substances at historical sites and the liability involved are often unsubstantiated and subject to dispute; however, federal law provides that all PRPs for a particular site may be 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, 2007, based on estimates of the total costs of cleanup, the Companies' proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. In addition, JCP&L has accrued liabilities of approximately $56 million for environmental remediation of former manufactured gas plants in New Jersey; those costs are being recovered by JCP&L through a non-bypassable SBC. Total liabilities of approximately $93 million have been accrued through December 31, 2007.

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

In August 2002, the trial court granted partial summary judgment to JCP&L and dismissed the plaintiffs' claims for consumer fraud, common law fraud, negligent misrepresentation, and strict product liability. In November 2003, the trial court granted JCP&L's motion to decertify the class and denied plaintiffs' motion to permit into evidence their class-wide damage model indicating damages in excess of $50 million. These class decertification and damage rulings were appealed to the Appellate Division. The Appellate Division issued a decision in July 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, NJ, based on a common incident involving the failure of the bushings of two large transformers in the Red Bank substation resulting in planned and unplanned outages in the area during a 2-3 day period. In 2005, JCP&L 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. Plaintiffs appealed this ruling to the New Jersey Appellate Division which, in March 2007, reversed the decertification of the Red Bank class and remanded this matter back to the Trial Court to allow plaintiffs sufficient time to establish a damage model or individual proof of damages. JCP&L filed a petition for allowance of an appeal of the Appellate Division ruling to the New Jersey Supreme Court which was denied in May 2007. Proceedings are continuing in the Superior Court. We are defending this class action but are unable to predict the outcome of this matter. No liability has been accrued as of December 31, 2007.

On August 14, 2003, various states and parts of southern Canada experienced widespread power outages. The outages affected approximately 1.4 million customers in our 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 our 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 us and ECAR to assess and understand perceived inadequacies within our 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). We believe 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. We remain 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 us, MISO, PJM, ECAR, and other parties to correct the causes of the August 14, 2003 power outages. We 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 our electric system. Our implementation of these recommendations in 2004 included completion of the Task Force recommendations that were directed toward us. We are 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.

On February 5, 2008, the PUCO entered an order dismissing four separate complaint cases before it relating to the August 14, 2003 power outages. The dismissal was filed by the complainants in accordance with a resolution reached between the FirstEnergy companies and the complainants in those four cases. Two of those cases which were originally filed in Ohio State courts involved individual complainants and were subsequently dismissed for lack of subject matter jurisdiction. Further appeals were unsuccessful. The other two complaint cases were filed by various insurance carriers either in their own name as subrogees or in the name of their insured, seeking reimbursement from various FirstEnergy companies (and, in one case, from PJM, MISO and AEP, as well) for claims paid to insureds for damages allegedly arising as a result of the loss of power on August 14, 2003. (Also relating to the August 14, 2003 power outages, a fifth case, involving another insurance company was voluntarily dismissed by the claimant in April 2007; and a sixth case, involving the claim of a non-customer seeking reimbursement for losses incurred when its store was burglarized on August 14, 2003 was dismissed by the court.) The order dismissing the PUCO cases, noted above, concludes all pending litigation related to the August 14, 2003 outages and the resolution will not have a material adverse effect on the financial condition, results of operations or cash flows of either us or any of our subsidiaries.

Nuclear Plant Matters

On May 14, 2007, the Office of Enforcement of the NRC issued a Demand for Information (DFI) to FENOC, following FENOC's reply to an April 2, 2007 NRC request for information, about two reports prepared by expert witnesses for an insurance arbitration (the insurance claim was subsequently withdrawn by us in December 2007) related to Davis-Besse. The NRC indicated that this information was needed for the NRC "to determine whether an Order or other action should be taken pursuant to 10 CFR 2.202, to provide reasonable assurance that FENOC will continue to operate its licensed facilities in accordance with the terms of its licenses and the Commission's regulations." FENOC was directed to submit the information to the NRC within 30 days. On June 13, 2007, FENOC filed a response to the NRC's Demand for Information reaffirming that it accepts full responsibility for the mistakes and omissions leading up to the damage to the reactor vessel head and that it remains committed to operating Davis-Besse and our other nuclear plants safely and responsibly. FENOC submitted a supplemental response clarifying certain aspects of the DFI response to the NRC on July 16, 2007. On August 15, 2007, the NRC issued a confirmatory order imposing these commitments. FENOC must inform the NRC's Office of Enforcement after it completes the key commitments embodied in the NRC's order. FENOC's compliance with these commitments is subject to future NRC review.

Other Legal Matters

There are various lawsuits, claims (including claims for asbestos exposure) and proceedings related to our normal business operations pending against us and our subsidiaries. The other potentially material items not otherwise discussed above are described below.

On August 22, 2005, a class action complaint was filed against OE in Jefferson County, Ohio Common Pleas Court, seeking compensatory and punitive damages to be determined at trial based on claims of negligence and eight other tort counts alleging damages from W.H. Sammis Plant air emissions. The two named plaintiffs are also seeking injunctive relief to eliminate harmful emissions and repair property damage and the institution of a medical monitoring program for class members. On April 5, 2007, the Court rejected the plaintiffs' request to certify this case as a class action and, accordingly, did not appoint the plaintiffs as class representatives or their counsel as class counsel. On July 30, 2007, plaintiffs' counsel voluntarily withdrew their request for reconsideration of the April 5, 2007 Court order denying class certification and the Court heard oral argument on the plaintiffs' motion to amend their complaint which OE has opposed. On August 2, 2007, the Court denied the plaintiffs' motion to amend their complaint. The plaintiffs have appealed the Court's denial of the motion for certification as a class action and motion to amend their complaint.

JCP&L's bargaining unit employees filed a grievance challenging JCP&L'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 JCP&L appeal of the award filed on October 18, 2005. A final order identifying the individual damage amounts was issued on October 31, 2007. The award appeal process was initiated. The union filed a motion with the federal court to confirm the award and JCP&L filed its answer and counterclaim to vacate the award on December 31, 2007. The court is expected to issue a briefing schedule at its April 2008 scheduling conference. JCP&L recognized a liability for the potential $16 million award in 2005.

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

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.

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.

Emission Allowances

We hold emission allowances for SO_2 and NO_X in order to comply with programs implemented by the EPA designed to regulate emissions of SO_2 and NO_X produced by power plants. Emission allowances are either granted to us by the EPA at zero cost or are purchased at fair value as needed to meet emission requirements. Emission allowances are not purchased with the intent of resale. Emission allowances eligible to be used in the current year are recorded in materials and supplies inventory at the lesser of weighted average cost or market value. Emission allowances eligible for use in future years are recorded as other investments. We recognize emission allowance costs as fuel expense during the periods that emissions are produced by our generating facilities. Excess emission allowances that are not needed to meet emission requirements may be sold and are reported as a reduction to other operating expenses.

Regulatory Accounting

Our energy delivery services segment is subject to regulation that sets the prices (rates) we are permitted to charge our customers based on costs that the regulatory agencies determine we are permitted to recover. At times, regulators permit the future recovery through rates of costs that would be currently charged to expense by an unregulated company. This ratemaking process results in the recording of regulatory assets based on anticipated future cash inflows. We regularly review these assets to assess their ultimate recoverability within the approved regulatory guidelines. Impairment risk associated with these assets relates to potentially adverse legislative, judicial or regulatory actions in the future.

Pension and Other Postretirement Benefits Accounting

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

In December 2006, we adopted SFAS 158 which requires a net liability or asset to be recognized for the overfunded or underfunded status of our defined benefit pension and other postretirement benefit plans on the balance sheet and recognize changes in funded status in the year in which the changes occur through other comprehensive income. We will continue to apply the provisions of SFAS 87 and SFAS 106 in measuring plan assets and benefit obligations as of the balance sheet date and in determining the amount of net periodic benefit cost. The overfunded status of our qualified pension and OPEB plans at December 31, 2007 is $136 million. Our non-qualified pension plans have an underfunded status of $165 million at December 31, 2007.

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 was 6.5%, 6.00% and 5.75% as of December 31, 2007, 2006 and 2005, respectively.

Our assumed rate of return on pension plan assets considers historical market returns and economic forecasts for the types of investments held by our pension trusts. In 2007, 2006 and 2005, our qualified pension plan assets actually earned $438 million or 8.2%, $567 million or 12.5% and $325 million or 8.2%, respectively. Our qualified pension costs in 2007, 2006 and 2005 were computed using an assumed 9.0% rate of return on plan assets which generated $449 million, $396 million and $345 million expected returns on plan assets, respectively. The 2007 expected return was based upon projections of future returns and our pension trust investment allocation of approximately 61% equities, 30% bonds, 7% real estate, 1% private equities and 1% cash. The gains or losses generated as a result of the difference between expected and actual returns on plan assets are deferred and amortized and will increase or decrease future net periodic pension expense, respectively.

Our qualified pension and OPEB net periodic benefit expense was a credit of $94 million in 2007 compared to an expense of $94 million and $131 million in 2006 and 2005, respectively. Our non-qualified net periodic pension expense was $21 million in 2007 and 2006 and $16 million in 2005. On January 2, 2007, we made a $300 million voluntary contribution to our pension plan. In addition, during 2006, we amended our OPEB plan, effective in 2008, to cap our monthly contribution for many of the retirees and their spouses receiving subsidized health care coverage. As a result of the $300 million voluntary contribution and the amendment to the OPEB plan effective in 2008, we expect our 2008 qualified pension and OPEB costs to be a credit of $137 million and our non-qualified pension costs to be an expense of $21 million.

Health care cost trends continue to increase and will affect future OPEB costs. The 2007 and 2006 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 our pension and OPEB costs from changes in key assumptions are as follows:

Increase in Costs from Adverse Changes in Key Assumptions

Assumption	Adverse Change	Pension	OPEB	Total
			(In millions)	
Discount rate	Decrease by 0.25%	$ 15	$ 3	$ 18
Long-term return on assets	Decrease by 0.25%	$ 13	$ 1	$ 14
Health care trend rate	Increase by 1%	N/A	$ 9	$ 9

Ohio Transition Cost Amortization

In connection with the Ohio Companies' transition plan, the PUCO determined allowable transition costs based on amounts recorded on the regulatory books of the Ohio Companies. These costs exceeded those deferred or capitalized on our balance sheet prepared under GAAP since they included certain costs which had not yet been incurred or that were recognized on the regulatory financial statements (fair value purchase accounting adjustments). We use an effective interest method for amortizing the Ohio Companies' transition costs, often referred to as a "mortgage-style" amortization. The interest rate under this method is equal to the rate of return authorized by the PUCO in the transition plan for each respective company. In computing the transition cost amortization, we include only the portion of the transition revenues associated with transition costs included on the balance sheet prepared under GAAP. Revenues collected for the off-balance sheet costs and the return associated with these costs are recognized as income when received. Amortization of deferred customer shopping incentives and interest costs are equal to the related revenue recovery that is recognized under the RCP (see Note 2(A)).

Long-Lived Assets

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

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

Asset Retirement Obligations

In accordance with SFAS 143 and FIN 47, we recognize an ARO for the future decommissioning of our nuclear power plants and future remediation of other environmental liabilities associated with all of our long-lived assets. The ARO liability represents an estimate of the fair value of our current obligation related to nuclear decommissioning and the retirement or remediation of environmental liabilities of other assets. A fair value measurement inherently involves uncertainty in the amount and timing of settlement of the liability. We use 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.

Income Taxes

We record 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 recognized for tax purposes. Investment tax credits, which were deferred when utilized, are being amortized over the recovery period of the related property. Deferred income tax liabilities related to tax and accounting basis differences and tax credit carryforward items are recognized at the statutory income tax rates in effect when the liabilities are expected to be paid. Deferred tax assets are recognized based on income tax rates expected to be in effect when they are settled.

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 goodwill for impairment at least annually and make such evaluations more frequently if indicators of impairment 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 impairment is indicated, we recognize a loss – calculated as the difference between the implied fair value of a reporting unit's goodwill and the carrying value of the goodwill. Our annual review was completed in the third quarter of 2007 with no impairment indicated.

During 2006, our annual review was completed in the third quarter with no impairment indicated. As discussed in Note 10 to the consolidated financial statements, the PPUC issued its order on January 11, 2007 related to the comprehensive rate filing made by Met-Ed and Penelec on April 10, 2006. Prior to issuing the order, the PPUC conducted an informal, nonbinding polling of Commissioners at its public meeting on December 21, 2006 that indicated that the rate increase ultimately granted could be substantially lower than the amounts requested. As a result of the polling, we determined that an interim review of goodwill for our energy delivery services segment would be required. No impairment was indicated as a result of that review.

SFAS 142 requires the goodwill of a reporting unit to be tested for impairment if there is a more-likely-than-not expectation that the reporting unit or a significant asset group within the reporting unit will be sold. In December 2005, MYR qualified as an asset held for sale in accordance with SFAS 144. As a result, in the fourth quarter of 2005, the goodwill of MYR was retested for impairment, resulting in a non-cash charge of $9 million (there was no corresponding income tax benefit).

The forecasts used in our evaluations 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.

NEW ACCOUNTING STANDARDS AND INTERPRETATIONS

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 and its related FSPs are effective for fiscal years beginning after November 15, 2007, and interim periods within those years. Under FSP FAS 157-2, we have elected to defer the election of SFAS 157 for financial assets and financial liabilities measured at fair value on a non-recurring basis for one year. We have evaluated the impact of this Statement and its FSPs, FSP FAS 157-2 and FSP FAS 157-1, which excludes SFAS 13, *Accounting for Leases,* and its related pronouncements from the scope of SFAS 157, and do not expect there to be a material effect on our financial statements. The majority of our fair value measurements will be disclosed as level 1 or level 2 in the fair value hierarchy.

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

In February 2007, the FASB issued SFAS 159, which provides companies with an option to report selected financial assets and financial liabilities at fair value. This Statement attempts to provide additional information that will help investors and other users of financial statements to more easily understand the effect of a 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 and SFAS 107. This Statement is effective for fiscal years beginning after November 15, 2007, and interim periods within those years. We have analyzed our financial assets and financial liabilities within the scope of this Statement and no fair value elections were made as of January 1, 2008.

SFAS 141(R) – "Business Combinations"

In December 2007, the FASB issued SFAS 141(R), which requires the acquiring entity in a business combination to recognize all the assets acquired and liabilities assumed in the transaction; establishes the acquisition-date fair value as the measurement objective for all assets acquired and liabilities assumed; and requires the acquirer to disclose to investors and other users all of the information they need to evaluate and understand the nature and financial effect of the business combination. SFAS 141(R) attempts to reduce the complexity of existing GAAP related to business combinations. The Standard includes both core principles and pertinent application guidance, eliminating the need for numerous EITF issues and other interpretative guidance. SFAS 141(R) will affect business combinations we enter that close after January 1, 2009. In addition, the Standard also affects the accounting for changes in tax valuation allowances made after January 1, 2009, that were established as part of a business combination prior to the implementation of this standard. We are currently evaluating the impact of adopting this Standard on our financial statements.

SFAS 160 - "Noncontrolling Interests in Consolidated Financial Statements – an Amendment of ARB No. 51"

In December 2007, the FASB issued SFAS 160 that establishes accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. It clarifies that a noncontrolling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. This Statement is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. Early adoption is prohibited. The Statement is not expected to have a material impact on our financial statements.

FSP FIN 39-1 – "Amendment of FASB Interpretation No. 39"

In April 2007, the FASB issued Staff Position (FSP) FIN 39-1, which permits an entity to offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) against fair value amounts recognized for derivative instruments that have been offset under the same master netting arrangement as the derivative instruments. This FSP is effective for fiscal years beginning after November 15, 2007, with early application permitted. The effects of applying the guidance in this FSP should be recognized as a retrospective change in accounting principle for all financial statements presented. FSP FIN 39-1 is not expected to have a material effect on our financial statements.

EITF 06-11 – "Accounting for Income Tax Benefits of Dividends or Share-based Payment Awards"

In June 2007, the FASB released EITF 06-11, which provides guidance on the appropriate accounting for income tax benefits related to dividends earned on nonvested share units that are charged to retained earnings under SFAS 123(R). The consensus requires that an entity recognize the realized tax benefit associated with the dividends on nonvested shares as an increase to APIC. This amount should be included in the APIC pool, which is to be used when an entity's estimate of forfeitures increases or actual forfeitures exceed its estimates, at which time the tax benefits in the APIC pool would be reclassified to the income statement. The consensus is effective for income tax benefits of dividends declared during fiscal years beginning after December 15, 2007. EITF 06-11 is not expected to have a material effect on our financial statements.

MANAGEMENT REPORTS

Management's Responsibility for Financial Statements

The consolidated financial statements of FirstEnergy Corp. (Company) were prepared by management, who takes responsibility for their integrity and objectivity. The statements were prepared in conformity with accounting principles generally accepted in the United States and are consistent with other financial information appearing elsewhere in this report. PricewaterhouseCoopers LLP, an independent registered public accounting firm, has expressed an unqualified opinion on the Company's 2007 consolidated financial statements.

The Company's internal auditors, who are responsible to the Audit Committee of the Company's Board of Directors, review the results and performance of operating units within the Company for adequacy, effectiveness and reliability of accounting and reporting systems, as well as managerial and operating controls.

The Company's Audit Committee consists of four independent directors whose duties include: consideration of the adequacy of the internal controls of the Company and the objectivity of financial reporting; inquiry into the number, extent, adequacy and validity of regular and special audits conducted by independent auditors and the internal auditors; and reporting to the Board of Directors the Committee's findings and any recommendation for changes in scope, methods or procedures of the auditing functions. The Committee is directly responsible for appointing the Company's independent registered public accounting firm and is charged with reviewing and approving all services performed for the Company by the independent registered public accounting firm and for reviewing and approving the related fees. The Committee reviews the independent registered public accounting firm's report on internal quality control and reviews all relationships between the independent registered public accounting firm and the Company, in order to assess the independent registered public accounting firm's independence. The Committee also reviews management's programs to monitor compliance with the Company's policies on business ethics and risk management. The Committee establishes procedures to receive and respond to complaints received by the Company regarding accounting, internal accounting controls, or auditing matters and allows for the confidential, anonymous submission of concerns by employees. The Audit Committee held nine meetings in 2007.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) of the Securities Exchange Act of 1934. Using the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control – Integrated Framework*, management conducted an evaluation of the effectiveness of the Company's internal control over financial reporting under the supervision of the chief executive officer and the chief financial officer. Based on that evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2007. The effectiveness of the Company's internal control over financial reporting, as of December 31, 2007, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears on page 62.

Report of Independent Registered Public Accounting Firm

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, capitalization, common stockholders' equity and cash flows present fairly, in all material respects, the financial position of FirstEnergy Corp. and its subsidiaries at December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included 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. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in the notes to the consolidated financial statements, the Company changed the manner in which it accounts for uncertain tax positions as of January 1, 2007 (Note 9), defined benefit pension and other postretirement plans as of December 31, 2006 (Note 3) and conditional asset retirement obligations as of December 31, 2005 (Note 2(G) and Note 12).

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP
Cleveland, Ohio
February 28, 2008

FIRSTENERGY CORP.

CONSOLIDATED STATEMENTS OF INCOME

For the Years Ended December 31,	2007	2006	2005
	(In millions, except per share amounts)		
REVENUES:			
Electric utilities	$ 11,305	$ 10,007	$ 9,703
Unregulated businesses	1,497	1,494	1,655
Total revenues*	12,802	11,501	11,358
EXPENSES:			
Fuel and purchased power	5,014	4,253	4,011
Other operating expenses	3,086	2,965	3,103
Provision for depreciation	638	596	588
Amortization of regulatory assets	1,019	861	1,281
Deferral of new regulatory assets	(524)	(500)	(405)
General taxes	754	720	713
Total expenses	9,987	8,895	9,291
OPERATING INCOME	2,815	2,606	2,067
OTHER INCOME (EXPENSE):			
Investment income	120	149	217
Interest expense	(775)	(721)	(660)
Capitalized interest	32	26	19
Subsidiaries' preferred stock dividends	-	(7)	(15)
Total other expense	(623)	(553)	(439)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	2,192	2,053	1,628
INCOME TAXES	883	795	749
INCOME FROM CONTINUING OPERATIONS	1,309	1,258	879
Discontinued operations (net of income tax benefits of $2 million and $4 million, respectively) (Note 8)	-	(4)	12
INCOME BEFORE CUMULATIVE EFFECT OF A CHANGE IN ACCOUNTING PRINCIPLE	1,309	1,254	891
Cumulative effect of a change in accounting principle (net of income tax benefit of $17 million) (Note 2(G))	-	-	(30)
NET INCOME	$ 1,309	$ 1,254	$ 861
BASIC EARNINGS PER SHARE OF COMMON STOCK:			
Income from continuing operations	$ 4.27	$ 3.85	$ 2.68
Discontinued operations (Note 8)	-	(0.01)	0.03
Cumulative effect of a change in accounting principle (Note 2(G))	-	-	(0.09)
Net earnings per basic share	$ 4.27	$ 3.84	$ 2.62
WEIGHTED AVERAGE NUMBER OF BASIC SHARES OUTSTANDING	306	324	328
DILUTED EARNINGS PER SHARE OF COMMON STOCK:			
Income from continuing operations	$ 4.22	$ 3.82	$ 2.67
Discontinued operations (Note 8)	-	(0.01)	0.03
Cumulative effect of a change in accounting principle (Note 2(G))	-	-	(0.09)
Net earnings per diluted share	$ 4.22	$ 3.81	$ 2.61
WEIGHTED AVERAGE NUMBER OF DILUTED SHARES OUTSTANDING	310	327	330

* Includes $424 million, $400 million and $395 million of excise tax collections in 2007, 2006 and 2005, respectively.

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

FIRSTENERGY CORP.

CONSOLIDATED BALANCE SHEETS

As of December 31,	2007	2006
	(In millions)	
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 129	$ 90
Receivables-		
Customers (less accumulated provisions of $36 million and $43 million, respectively, for uncollectible accounts)	1,256	1,135
Other (less accumulated provisions of $22 million and $24 million, respectively, for uncollectible accounts)	165	132
Materials and supplies, at average cost	521	577
Prepayments and other	159	149
	2,230	2,083
PROPERTY, PLANT AND EQUIPMENT:		
In service	24,619	24,105
Less - Accumulated provision for depreciation	10,348	10,055
	14,271	14,050
Construction work in progress	1,112	617
	15,383	14,667
INVESTMENTS:		
Nuclear plant decommissioning trusts	2,127	1,977
Investments in lease obligation bonds (Note 6)	717	811
Other	754	746
	3,598	3,534
DEFERRED CHARGES AND OTHER ASSETS:		
Goodwill	5,607	5,898
Regulatory assets	3,945	4,441
Pension assets (Note 3)	700	-
Other	605	573
	10,857	10,912
	$ 32,068	$ 31,196
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES:		
Currently payable long-term debt	$ 2,014	$ 1,867
Short-term borrowings (Note 13)	903	1,108
Accounts payable	777	726
Accrued taxes	408	598
Other	1,046	956
	5,148	5,255
CAPITALIZATION (See Consolidated Statements of Capitalization):		
Common stockholders' equity	8,977	9,035
Long-term debt and other long-term obligations	8,869	8,535
	17,846	17,570
NONCURRENT LIABILITIES:		
Accumulated deferred income taxes	2,671	2,740
Asset retirement obligations	1,267	1,190
Deferred gain on sale and leaseback transaction	1,060	-
Power purchase contract loss liability	750	1,182
Retirement benefits	894	944
Lease market valuation liability	663	767
Other	1,769	1,548
	9,074	8,371
COMMITMENTS, GUARANTEES AND CONTINGENCIES (Notes 6 and 14)		
	$ 32,068	$ 31,196

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

FIRSTENERGY CORP.

CONSOLIDATED STATEMENTS OF CAPITALIZATION

As of December 31,	2007	2006
(Dollars in millions)		
COMMON STOCKHOLDERS' EQUITY:		
Common stock, $0.10 par value - authorized 375,000,000 shares - 304,835,407 and 319,205,517 shares outstanding, respectively	$ 31	$ 32
Other paid-in capital	5,509	6,466
Accumulated other comprehensive loss (Note 2(F))	(50)	(259)
Retained earnings (Note 11(A))	3,487	2,806
Unallocated employee stock ownership plan common stock- 521,818 shares in 2006 (Note 4(B))	-	(10)
Total common stockholders' equity	8,977	9,035

LONG-TERM DEBT AND OTHER LONG-TERM OBLIGATIONS (Note 11(C)):
(Interest rates reflect weighted average rates)

	FIRST MORTGAGE BONDS			SECURED NOTES			UNSECURED NOTES			TOTAL	
	%	2007	2006	%	2007	2006	%	2007	2006	2007	2006
Ohio Edison Company-											
Due 2007-2012	-	$ -	$ -	7.01	$ 4	$ 8	4.65	$ 331	$ 331		
Due 2013-2017	-	-	-	-	-	-	6.04	400	400		
Due 2028-2032	-	-	-	5.38	13	120	-	-	-		
Due 2033-2037	-	-	-	-	-	-	6.88	350	350		
Total-Ohio Edison		-	-		17	128		1,081	1,081	1,098	1,209
Cleveland Electric Illuminating Company-											
Due 2007-2012	6.86	125	125	6.13	232	351	-	-	-		
Due 2013-2017	-	-	-	7.88	300	300	5.67	550	379		
Due 2018-2022	-	-	-	-	-	133	-	-	-		
Due 2028-2032	-	-	-	5.38	6	6	-	-	103		
Due 2033-2037	-	-	-	-	-	54	5.95	300	300		
Total-Cleveland Electric		125	125		538	844		850	782	1,513	1,751
Toledo Edison Company-											
Due 2007-2012	-	-	-	-	-	30	-	-	-		
Due 2023-2027	-	-	-	-	-	10	-	-	-		
Due 2028-2032	-	-	-	5.38	4	4	-	-	-		
Due 2033-2037	-	-	-	-	-	45	6.15	300	300		
Total-Toledo Edison		-	-		4	89		300	300	304	389
Pennsylvania Power Company-											
Due 2007-2012	9.74	5	6	-	-	-	-	-	-		
Due 2013-2017	9.74	5	5	5.40	1	1	-	-	-		
Due 2018-2022	9.74	2	2	-	-	-	-	-	-		
Due 2023-2027	7.63	6	6	-	-	-	-	-	-		
Due 2028-2032	-	-	-	5.38	2	2	-	-	-		
Total-Penn Power		18	19		3	3		-	-	21	22
Jersey Central Power & Light Company-											
Due 2007-2012	-	-	-	5.50	154	187	-	-	-		
Due 2013-2017	-	-	12	5.89	187	487	5.64	550	-		
Due 2018-2022	-	-	-	5.60	56	206	4.80	150	-		
Due 2023-2027	-	-	275	-	-	-	-	-	-		
Due 2033-2037	-	-	-	-	-	200	6.25	500	-		
Total-Jersey Central		-	287		397	1,080		1,200	-	1,597	1,367
Metropolitan Edison Company-											
Due 2007-2012	-	-	-	-	-	-	4.45	100	150		
Due 2013-2017	-	-	-	-	-	-	4.90	400	400		
Due 2018-2022	-	-	-	-	-	-	4.66	28	28		
Due 2023-2027	5.95	14	14	-	-	-	-	-	-		
Total-Metropolitan Edison		14	14		-	-		528	578	542	592
Pennsylvania Electric Company-											
Due 2007-2012	5.35	24	24	-	-	-	6.55	135	135		
Due 2013-2017	-	-	-	-	-	-	5.74	450	150		
Due 2018-2022	-	-	-	-	-	-	6.32	145	145		
Due 2023-2027	-	-	-	-	-	-	4.51	25	25		
Total-Pennsylvania Electric		24	24		-	-		755	455	779	479

FIRSTENERGY CORP.

CONSOLIDATED STATEMENTS OF CAPITALIZATION (Cont'd)

As of December 31,

(Dollars in millions)

LONG-TERM DEBT AND OTHER LONG-TERM OBLIGATIONS (Cont'd)
(Interest rates reflect weighted average rates)

	FIRST MORTGAGE BONDS			SECURED NOTES			UNSECURED NOTES			TOTAL	
	%	2007	2006	%	2007	2006	%	2007	2006	2007	2006
FirstEnergy Corp.-											
Due 2007-2012	-	-	-	-	-	-	6.45	1,500	1,500		
Due 2028-2032	-	-	-	-	-	-	7.38	1,500	1,500		
Total-FirstEnergy		-	-		-	-		3,000	3,000	3,000	3,000
Bay Shore Power	-	-	-	6.25	125	130	-	-	-	125	130
FirstEnergy Generation	-	-	-	-	-	-	4.06	871	624	871	624
FirstEnergy Nuclear Generation	-	-	-	-	-	-	4.24	1,041	861	1,041	861
Total		181	469		1,084	2,274		9,626	7,681	10,891	10,424
Capital lease obligations										4	4
Net unamortized discount on debt										(12)	(26)
Long-term debt due within one year										(2,014)	(1,867)
Total long-term debt and other long-term obligations										8,869	8,535
TOTAL CAPITALIZATION										$ 17,846	$ 17,570

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

FIRSTENERGY CORP.

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY

	Comprehensive Income	Common Stock Number of Shares	Common Stock Par Value	Other Paid-In Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Unallocated ESOP Common Stock
				(Dollars in millions)			
Balance, January 1, 2005		329,836,276	$ 33	$ 7,056	$ (313)	$ 1,857	$ (43)
Net income	$ 861					861	
Minimum liability for unfunded retirement benefits, net of $208 million of income taxes	295				295		
Unrealized gain on derivative hedges, net of $9 million of income taxes	14				14		
Unrealized loss on investments, net of $15 million of income tax benefits	(16)				(16)		
Comprehensive income	$ 1,154						
Stock options exercised				(41)			
Allocation of ESOP shares				22			16
Restricted stock units				6			
Cash dividends declared on common stock						(559)	
Balance, December 31, 2005		329,836,276	33	7,043	(20)	2,159	(27)
Net income	$ 1,254					1,254	
Unrealized gain on derivative hedges, net of $10 million of income taxes	19				19		
Unrealized gain on investments, net of $40 million of income taxes	69				69		
Comprehensive income	$ 1,342						
Net liability for unfunded retirement benefits due to the implementation of SFAS 158, net of $292 million of income tax benefits (Note 3)					(327)		
Redemption premiums on preferred stock						(9)	
Stock options exercised				(28)			
Allocation of ESOP shares				33			17
Restricted stock units				11			
Stock based compensation				6			
Repurchase of common stock		(10,630,759)	(1)	(599)			
Cash dividends declared on common stock						(598)	
Balance, December 31, 2006		319,205,517	32	6,466	(259)	2,806	(10)
Net income	$ 1,309					1,309	
Unrealized loss on derivative hedges, net of $8 million of income tax benefits	(17)				(17)		
Unrealized gain on investments, net of $31 million of income taxes	47				47		
Pension and other postretirement benefits, net of $169 million of income taxes (Note 3)	179				179		
Comprehensive income	$ 1,518						
Stock options exercised				(40)			
Allocation of ESOP shares				26			10
Restricted stock units				23			
Stock based compensation				2			
FIN 48 cumulative effect adjustment						(3)	
Repurchase of common stock		(14,370,110)	(1)	(968)			
Cash dividends declared on common stock						(625)	
Balance, December 31, 2007		304,835,407	$ 31	$ 5,509	$ (50)	$ 3,487	$ -

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

FIRSTENERGY CORP.

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31,	2007	2006	2005
		(In millions)	
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 1,309	$ 1,254	$ 861
Adjustments to reconcile net income to net cash from operating activities-			
Provision for depreciation	638	596	588
Amortization of regulatory assets	1,019	861	1,281
Deferral of new regulatory assets	(524)	(500)	(405)
Nuclear fuel and lease amortization	101	90	90
Deferred purchased power and other costs	(346)	(445)	(384)
Deferred income taxes and investment tax credits, net	(9)	159	154
Investment impairment (Note 2(E))	26	27	6
Cumulative effect of a change in accounting principle	-	-	30
Deferred rents and lease market valuation liability	(99)	(113)	(104)
Accrued compensation and retirement benefits	(37)	193	90
Tax refunds related to pre-merger period	-	-	18
Commodity derivative transactions, net	6	24	6
Gain on asset sales	(30)	(49)	(35)
Loss (income) from discontinued operations (Note 8)	-	4	(12)
Cash collateral, net	(68)	(77)	196
Pension trust contributions	(300)	-	(500)
Decrease (increase) in operating assets-			
Receivables	(136)	105	(87)
Materials and supplies	79	(25)	(32)
Prepayments and other current assets	10	3	3
Increase (decrease) in operating liabilities-			
Accounts payable	51	99	32
Accrued taxes	71	(175)	150
Accrued interest	(8)	7	(6)
Electric service prepayment programs	(75)	(64)	208
Other	16	(35)	72
Net cash provided from operating activities	1,694	1,939	2,220
CASH FLOWS FROM FINANCING ACTIVITIES:			
New Financing-			
Long-term debt	1,527	2,739	721
Short-term borrowings, net	-	386	561
Redemptions and Repayments-			
Common stock	(969)	(600)	-
Preferred stock	-	(193)	(170)
Long-term debt	(1,098)	(2,536)	(1,424)
Short-term borrowings, net	(205)	-	-
Net controlled disbursement activity	(1)	(27)	(18)
Stock-based compensation tax benefit	20	13	-
Common stock dividend payments	(616)	(586)	(546)
Net cash used for financing activities	(1,342)	(804)	(876)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Property additions	(1,633)	(1,315)	(1,208)
Proceeds from asset sales	42	162	104
Proceeds from sale and leaseback transaction	1,329	-	-
Sales of investment securities held in trusts	1,294	1,651	1,587
Purchases of investment securities held in trusts	(1,397)	(1,666)	(1,688)
Cash investments and restricted funds (Note 5)	72	121	(42)
Other	(20)	(62)	(86)
Net cash used for investing activities	(313)	(1,109)	(1,333)
Net increase in cash and cash equivalents	39	26	11
Cash and cash equivalents at beginning of year	90	64	53
Cash and cash equivalents at end of year	$ 129	$ 90	$ 64
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash Paid During the Year-			
Interest (net of amounts capitalized)	$ 744	$ 656	$ 665
Income taxes	$ 710	$ 688	$ 406

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND BASIS OF PRESENTATION

FirstEnergy is a diversified energy company that holds, directly or indirectly, all of the outstanding common stock of its principal subsidiaries: OE, CEI, TE, Penn (a wholly owned subsidiary of OE), ATSI, JCP&L, Met-Ed, Penelec, FENOC, FES and its subsidiaries FGCO and NGC, and FESC.

FirstEnergy and its subsidiaries follow GAAP and comply with the regulations, orders, policies and practices prescribed by the SEC, FERC and, as applicable, the PUCO, PPUC and NJBPU. The preparation of financial statements in conformity with GAAP requires management to make periodic estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and disclosure of contingent assets and liabilities. Actual results could differ from these estimates. The reported results of operations are not indicative of results of operations for any future period.

FirstEnergy and its subsidiaries consolidate all majority-owned subsidiaries over which they exercise control and, when applicable, entities for which they have a controlling financial interest. Intercompany transactions and balances are eliminated in consolidation. FirstEnergy consolidates a VIE (see Note 7) when it is determined to be the VIE's primary beneficiary. Investments in non-consolidated affiliates over which FirstEnergy and its subsidiaries have the ability to exercise significant influence, but not control (20-50% owned companies, joint ventures and partnerships) are accounted for under the equity method. Under the equity method, the interest in the entity is reported as an investment in the Consolidated Balance Sheets and the percentage share of the entity's earnings is reported in the Consolidated Statements of Income.

Certain prior year amounts have been reclassified to conform to the current year presentation. Effective January 1, 2007, FirstEnergy changed its external segment reporting structure to reflect the operations of its core business segments and to align its external segment reporting with internal management reporting. As discussed in Note 16, segment reporting in 2006 and 2005 was reclassified to conform to the 2007 business segment organization and operations.

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

FirstEnergy accounts for the effects of regulation through the application of SFAS 71 to its operating utilities since their 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 net regulatory assets are removed from the balance sheet in accordance with the guidance in SFAS 101.

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

- restructuring the electric generation business and allowing the Companies' customers to select a competitive electric generation supplier other than the Companies;
- establishing or defining the PLR obligations to customers in the Companies' service areas;
- providing the Companies with the opportunity to recover potentially stranded investment (or transition costs) not otherwise recoverable in a competitive generation market;
- itemizing (unbundling) the price of electricity into its component elements – including generation, transmission, distribution and stranded costs recovery charges;
- continuing regulation of the Companies' transmission and distribution systems; and
- requiring corporate separation of regulated and unregulated business activities.

Regulatory Assets

The Companies and ATSI recognize, as regulatory assets, costs which the FERC, PUCO, PPUC and 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 expense as incurred. Regulatory assets that do not earn a current return totaled approximately $140 million as of December 31, 2007 (JCP&L - $84 million, Met-Ed - $54 million and Penelec - $2 million). Regulatory assets not earning a current return will be recovered by 2014 for JCP&L and by 2020 for Met-Ed and Penelec.

Regulatory assets on the Consolidated Balance Sheets are comprised of the following:

	2007	2006
	(In millions)	
Regulatory transition costs	$ 2,363	$ 3,266
Customer shopping incentives	516	603
Customer receivables for future income taxes	295	217
Loss on reacquired debt	57	43
Employee postretirement benefit costs	39	47
Nuclear decommissioning, decontamination and spent fuel disposal costs	(115)	(145)
Asset removal costs	(183)	(168)
MISO/PJM transmission costs	340	213
Fuel costs – RCP	220	113
Distribution costs – RCP	321	155
Other	92	97
Total	$ 3,945	$ 4,441

In accordance with the RCP, recovery of the aggregate of the regulatory transition costs and the Extended RTC (deferred customer shopping incentives and interest costs) amounts are expected to be complete for OE and TE by December 31, 2008. CEI's recovery of regulatory transition costs is projected to be complete by April 2009 at which time recovery of its Extended RTC will begin, with recovery estimated to be complete as of December 31, 2010. At the end of their respective recovery periods, any remaining unamortized regulatory transition costs and Extended RTC balances will be reduced by applying any remaining cost of removal regulatory liability balances – any remaining regulatory transition costs and Extended RTC balances will be written off. The RCP allows the Ohio Companies to defer and capitalize certain distribution costs during the period January 1, 2006 through December 31, 2008, not to exceed $150 million in each of the years 2006, 2007 and 2008. These deferrals will be recovered in distribution rates effective on or after January 1, 2009. In addition, the Ohio Companies deferred certain fuel costs through December 31, 2007 that were incurred above the amount collected through a fuel recovery mechanism in accordance with the RCP (see Note 10(B)).

Transition Cost Amortization

OE, CEI and TE amortize transition costs (see "Regulatory Matters – Ohio") using the effective interest method. Extended RTC amortization is equal to the related revenue recovery that is recognized. The following table provides the estimated net amortization of regulatory transition costs and Extended RTC amounts (including associated carrying charges) under the RCP for the period 2008 through 2010:

Amortization Period	OE	CEI	TE	Total Ohio
		(In millions)		
2008	$ 207	$ 126	$ 113	$ 446
2009	-	212	-	212
2010	-	273	-	273
Total Amortization	$ 207	$ 611	$ 113	$ 931

Total regulatory transition costs as of December 31, 2007 were $2.4 billion, of which approximately $1.6 billion and $237 million apply to JCP&L and Met-Ed, respectively. JCP&L's and Met-Ed's regulatory transition costs include the deferral of above-market costs for power supplied from NUGs of $875 million for JCP&L (recovered through BGS and MTC revenues) and $185 million for Met-Ed (recovered through CTC revenues). The liability for JCP&L's 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 pursuant to various regulatory proceedings in New Jersey and Pennsylvania (See Note 10).

(B) REVENUES AND RECEIVABLES

The Companies' principal business is providing electric service to customers in Ohio, Pennsylvania and New Jersey. The Companies' 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 Companies accrue the estimated unbilled amount receivable as revenue and reverse 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, 2007 with respect to any particular segment of FirstEnergy's customers. Total customer receivables were $1.3 billion (billed – $734 million and unbilled – $524 million) and $1.1 billion (billed – $650 million and unbilled – $485 million) as of December 31, 2007 and 2006, respectively.

(C) EARNINGS PER SHARE OF COMMON STOCK

Basic earnings per share of common stock is computed using the weighted average of actual common shares outstanding during the respective period as the denominator. The denominator for diluted earnings per share of common stock reflects the weighted average of common shares outstanding plus the potential additional common shares that could result if dilutive securities and other agreements to issue common stock were exercised. The pool of stock-based compensation tax benefits is calculated in accordance with SFAS 123(R). On August 10, 2006, FirstEnergy repurchased 10.6 million shares, approximately 3.2%, of its outstanding common stock through an accelerated share repurchase program. The initial purchase price was $600 million, or $56.44 per share. A final purchase price adjustment of $27 million was settled in cash on April 2, 2007. On March 2, 2007, FirstEnergy repurchased approximately 14.4 million shares, or 4.5%, of its outstanding common stock through an additional accelerated share repurchase program at an initial price of $62.63 per share, or a total initial purchase price of approximately $900 million. A final purchase price adjustment of $51 million was settled in cash on December 13, 2007. The basic and diluted earnings per share calculations shown below reflect the impact associated with these accelerated share repurchase programs.

Reconciliation of Basic and Diluted Earnings per Share of Common Stock	2007	2006	2005
	(In millions, except per share amounts)		
Income from continuing operations	$ 1,309	$ 1,258	$ 879
Less: Redemption premium on subsidiary preferred stock	-	(9)	-
Income from continuing operations available to common shareholders	1,309	1,249	879
Discontinued operations	-	(4)	12
Income before cumulative effect of a change in accounting principle	1,309	1,245	891
Cumulative effect of a change in accounting principle	-	-	(30)
Net income available for common shareholders	$ 1,309	$ 1,245	$ 861
Average shares of common stock outstanding – Basic	306	324	328
Assumed exercise of dilutive stock options and awards	4	3	2
Average shares of common stock outstanding – Dilutive	310	327	330
Earnings per share:			
Basic earnings per share:			
Earnings from continuing operations	$ 4.27	$ 3.85	$ 2.68
Discontinued operations	-	(0.01)	0.03
Cumulative effect of change in accounting principle	-	-	(0.09)
Net earnings per basic share	$ 4.27	$ 3.84	$ 2.62
Diluted earnings per share:			
Earnings from continuing operations	$ 4.22	$ 3.82	$ 2.67
Discontinued operations	-	(0.01)	0.03
Cumulative effect of change in accounting principle	-	-	(0.09)
Net earnings per diluted share	$ 4.22	$ 3.81	$ 2.61

(D) PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment reflects original cost (except for nuclear generating assets which were adjusted to fair value in accordance with SFAS 144), including payroll and related costs such as taxes, employee benefits, administrative and general costs, and interest costs incurred to place the assets in service. The costs of normal maintenance, repairs and minor replacements are expensed as incurred. FirstEnergy's accounting policy for planned major maintenance projects is to recognize liabilities as they are incurred. Property, plant and equipment balances as of December 31, 2007 and 2006 were as follows:

	December 31, 2007			December 31, 2006		
Property, Plant and Equipment	**Unregulated**	**Regulated**	**Total**	**Unregulated**	**Regulated**	**Total**
			(In millions)			
In service	$ 8,795	$ 15,824	$ 24,619	$ 8,915	$ 15,190	$ 24,105
Less accumulated depreciation	(4,037)	(6,311)	(10,348)	(4,014)	(6,041)	(10,055)
Net plant in service	$ 4,758	$ 9,513	$ 14,271	$ 4,901	$ 9,149	$ 14,050

FirstEnergy provides for depreciation on a straight-line basis at various rates over the estimated lives of property included in plant in service. The respective annual composite rates for FirstEnergy's subsidiaries' electric plant in 2007, 2006 and 2005 are shown in the following table:

	Annual Composite Depreciation Rate		
	2007	**2006**	**2005**
OE	2.9%	2.8%	2.1%
CEI	3.6	3.2	2.9
TE	3.9	3.8	3.1
Penn	2.3	2.6	2.4
JCP&L	2.1	2.1	2.2
Met-Ed	2.3	2.3	2.4
Penelec	2.3	2.3	2.6
FGCO	4.0	4.1	N/A
NGC	2.8	2.7	N/A

Jointly-Owned Generating Stations

JCP&L holds a 50% ownership interest in Yards Creek Pumped Storage Facility with a net book value of approximately $19.5 million as of December 31, 2007.

Asset Retirement Obligations

FirstEnergy recognizes a liability for retirement obligations associated with tangible assets in accordance with SFAS 143 and FIN 47. These standards require 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 value of the long-lived asset and depreciated over time, as described further in Note 12.

Nuclear Fuel

Property, plant and equipment includes nuclear fuel recorded at original cost, which includes material, enrichment, fabrication and interest costs incurred prior to reactor load. Nuclear fuel is amortized based on the units of production method.

(E) ASSET IMPAIRMENTS

Long-Lived Assets

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

Goodwill

In a business combination, the excess of the purchase price over the estimated fair values of assets acquired and liabilities assumed is recognized as goodwill. Based on the guidance provided by SFAS 142, FirstEnergy evaluates its goodwill for impairment at least annually and makes such evaluations more frequently if indicators of impairment arise. In accordance with the accounting standard, if the fair value of a reporting unit is less than its carrying value (including goodwill), the goodwill is tested for impairment. If an impairment is indicated, FirstEnergy recognizes a loss – calculated as the difference between the implied fair value of a reporting unit's goodwill and the carrying value of the goodwill. FirstEnergy's 2007 annual review was completed in the third quarter of 2007 with no impairment indicated. In the third quarter of 2007, FirstEnergy adjusted goodwill for the former GPU companies due to the realization of tax benefits that had been reserved in purchase accounting.

FirstEnergy's 2006 annual review was completed in the third quarter of 2006 with no impairment indicated. As discussed in Note 10 to the consolidated financial statements, the PPUC issued its order on January 11, 2007 related to the comprehensive rate filing made by Met-Ed and Penelec on April 10, 2006. Prior to issuing the order, the PPUC conducted an informal, nonbinding polling of Commissioners at its public meeting on December 21, 2006 that indicated that the rate increase ultimately granted could be substantially lower than the amounts requested. As a result of the polling, FirstEnergy determined that an interim review of goodwill for its energy delivery services segment would be required. No impairment was indicated as a result of that review.

The forecasts used in FirstEnergy's evaluations of goodwill reflect operations consistent with its general business assumptions. Unanticipated changes in those assumptions could have a significant effect on FirstEnergy's future evaluations of goodwill. FirstEnergy's goodwill primarily relates to its energy delivery services segment. The impairment analysis includes a significant source of cash representing the Companies' recovery of transition costs as described in Note 10. FirstEnergy estimates that completion of transition cost recovery will not result in an impairment of goodwill relating to its energy delivery services segment.

A summary of the changes in FirstEnergy's goodwill for the three years ended December 31, 2007 is shown below by segment (see Note 16 - Segment Information):

	Energy Delivery Services	Competitive Energy Services	Ohio Transitional Generation Services	Other	Consolidated
			(In millions)		
Balance as of January 1, 2005	$ 5,951	$ 24	$ -	$ 75	$ 6,050
Impairment charges				(9)	(9)
Non-core asset sales				(12)	(12)
Adjustments related to GPU acquisition	(10)				(10)
Adjustments related to Centerior acquisition	(9)				(9)
Balance as of December 31, 2005	5,932	24	-	54	6,010
Non-core asset sale				(53)	(53)
Adjustments related to Centerior acquisition	(1)				(1)
Adjustments related to GPU acquisition	(58)				(58)
Balance as of December 31, 2006	5,873	24	-	1	5,898
Adjustments related to GPU acquisition	(290)				(290)
Other				(1)	(1)
Balance as of December 31, 2007	$ 5,583	$ 24	$ -	$ -	$ 5,607

Investments

At the end of each reporting period, FirstEnergy 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. FirstEnergy 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. Upon adoption of FSP SFAS 115-1 and SFAS 124-1, FirstEnergy began recognizing in earnings the unrealized losses on available-for-sale securities held in its nuclear decommissioning trusts since the trust arrangements, as they are currently defined, do not meet the required ability and intent to hold criteria in consideration of other-than-temporary impairment. The fair value and unrealized gains and losses of FirstEnergy's investments are disclosed in Note 5.

(F) COMPREHENSIVE INCOME

Comprehensive income includes net income as reported on the Consolidated Statements of Income and all other changes in common stockholders' equity except those resulting from transactions with stockholders and from the adoption of SFAS 158. As of December 31, 2007, AOCL consisted of a net liability for unfunded retirement benefits including the implementation of SFAS 158, net of income tax benefits (see Note 3) of $166 million, unrealized gains on investments in available-for-sale securities of $191 million and unrealized losses on derivative instrument hedges of $75 million. A summary of the changes in FirstEnergy's AOCL balance for the three years ended December 31, 2007 is shown below:

	2007	2006	2005
		(In millions)	
AOCL balance as of January 1	$ (259)	$ (20)	$ (313)
Minimum liability for unfunded retirement benefits	-	-	503
Pension and other postretirement benefits:			
Prior service credit	(135)	-	-
Actuarial gain	483	-	-
Unrealized gain (loss) on available for sale securities	78	109	(31)
Unrealized gain (loss) on derivative hedges	(25)	29	23
Other comprehensive income	401	138	495
Income taxes related to OCI	192	50	202
Other comprehensive income, net of tax	209	88	293
Net liability for unfunded retirement benefits due to the implementation of SFAS 158, net of $292 million of income tax benefits	-	(327)	-
AOCL balance as of December 31	$ (50)	$ (259)	$ (20)

Other comprehensive income (loss) reclassified to net income in the three years ended December 31, 2007 is as follows:

	2007	2006	2005
		(In millions)	
Pension and other postretirement benefits, net of income tax benefits of $20 million	$ (25)	$ -	$ -
Gain (loss) on available for sale securities, net of income taxes (benefits) of $(6) million, $11 million and $27 million, respectively	(10)	16	40
Loss on derivative hedges, net of income tax benefits of $10 million, $12 million and $8 million, respectively	(16)	(20)	(12)
	$ (51)	$ (4)	$ 28

(G) CUMULATIVE EFFECT OF A CHANGE IN ACCOUNTING PRINCIPLE

Results in 2005 included an after-tax charge of $30 million recorded upon the adoption of FIN 47 in December 2005. FirstEnergy identified applicable legal obligations as defined under FIN 47 at its active and retired generating units, substation control rooms, service center buildings, line shops and office buildings, identifying asbestos as the primary conditional ARO. FirstEnergy recorded a conditional ARO liability of $57 million (including accumulated accretion for the period from the date the liability was incurred to the date of adoption), an asset retirement cost of $16 million (recorded as part of the carrying amount of the related long-lived asset), and accumulated depreciation of $12 million. FirstEnergy charged regulatory liabilities for $5 million upon adoption of FIN 47 for the transition amounts related to establishing the ARO for asbestos removal from substation control rooms and service center buildings for OE, Penn, CEI, TE and JCP&L. The remaining cumulative effect adjustment for unrecognized depreciation and accretion of $48 million was charged to income ($30 million, net of tax), or $0.09 per share of common stock (basic and diluted) for the year ended December 31, 2005 (see Note 12).

3. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS

FirstEnergy provides noncontributory defined benefit pension plans that cover substantially all of its employees and non-qualified pension plans that cover certain employees. The trusteed 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. On January 2, 2007, FirstEnergy made a $300 million voluntary cash contribution to its qualified pension plan. Projections indicate that additional cash contributions will not be required before 2017.

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. FirstEnergy 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, 2007.

In December 2006, FirstEnergy adopted SFAS 158. This Statement requires employers 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. The incremental impact of adopting SFAS 158 was a decrease of $1.0 billion in pension assets, a decrease of $383 million in pension liabilities and a decrease in AOCL of $327 million, net of tax.

Obligations and Funded Status As of December 31	Pension Benefits 2007	Pension Benefits 2006	Other Benefits 2007	Other Benefits 2006
		(In millions)		
Change in benefit obligation				
Benefit obligation as of January 1	$ 5,031	$ 4,911	$ 1,201	$ 1,884
Service cost	88	87	21	34
Interest cost	294	276	69	105
Plan participants' contributions	-	-	23	20
Plan amendments	-	-	-	(620)
Medicare retiree drug subsidy	-	-	-	6
Actuarial (gain) loss	(381)	38	(30)	(119)
Benefits paid	(282)	(281)	(102)	(109)
Benefit obligation as of December 31	$ 4,750	$ 5,031	$ 1,182	$ 1,201
Change in fair value of plan assets				
Fair value of plan assets as of January 1	$ 4,818	$ 4,525	$ 607	$ 573
Actual return on plan assets	438	567	43	69
Company contribution	311	7	47	54
Plan participants' contribution	-	-	23	20
Benefits paid	(282)	(281)	(102)	(109)
Fair value of plan assets as of December 31	$ 5,285	$ 4,818	$ 618	$ 607
Qualified plan	$ 700	$ (43)		
Non-qualified plans	(165)	(170)		
Funded status	$ 535	$ (213)	$ (564)	$ (594)
Accumulated benefit obligation	$ 4,397	$ 4,585		
Amounts Recognized in the Statement of Financial Position				
Noncurrent assets	$ 700	$ -	$ -	$ -
Current liabilities	(7)	(7)	-	-
Noncurrent liabilities	(158)	(206)	(564)	(594)
Net asset (liability) as of December 31	$ 535	$ (213)	$ (564)	$ (594)
Amounts Recognized in Accumulated Other Comprehensive Income				
Prior service cost (credit)	$ 83	$ 97	$ (1,041)	$ (1,190)
Actuarial loss	623	1,039	635	702
Net amount recognized	$ 706	$ 1,136	$ (406)	$ (488)
Assumptions Used to Determine Benefit Obligations As of December 31				
Discount rate	6.50%	6.00%	6.50%	6.00%
Rate of compensation increase	5.20%	3.50%		
Allocation of Plan Assets As of December 31				
Asset Category				
Equity securities	61%	64%	69%	72%
Debt securities	30	29	27	26
Real estate	7	5	2	1
Private equities	1	1	-	-
Cash	1	1	2	1
Total	100%	100%	100%	100%

Estimated Items to be Amortized in 2008 Net Periodic Pension Cost from Accumulated Other Comprehensive Income	Pension Benefits	Other Benefits
	(In millions)	
Prior service cost (credit)	$ 13	$ (149)
Actuarial loss	$ 8	$ 47

Components of Net Periodic Benefit Costs (Credit)	Pension Benefits 2007	2006	2005	Other Benefits 2007	2006	2005
			(In millions)			
Service cost	$ 88	$ 87	$ 80	$ 21	$ 34	$ 40
Interest cost	294	276	262	69	105	111
Expected return on plan assets	(449)	(396)	(345)	(50)	(46)	(45)
Amortization of prior service cost	13	13	10	(149)	(76)	(45)
Recognized net actuarial loss	45	62	39	45	56	40
Net periodic cost (credit)	$ (9)	$ 42	$ 46	$ (64)	$ 73	$ 101

Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31	Pension Benefits 2007	2006	2005	Other Benefits 2007	2006	2005
Discount rate	6.00%	5.75%	6.00%	6.00%	5.75%	6.00%
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 FirstEnergy'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.

FirstEnergy has assessed the impact of recent market developments, including a series of rating agency downgrades of subprime mortgage-related assets, on the value of the assets held in its pension and other postretirement benefit trusts. Based on this assessment, FirstEnergy believes that the fair value of its investments as of December 31, 2007 will not be materially affected by the subprime credit crisis due to their relatively small exposure to subprime assets.

Assumed Health Care Cost Trend Rates As of December 31	2007	2006
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)	2015-2017	2011-2013

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
	(In millions)	
Effect on total of service and interest cost	$ 5	$ (4)
Effect on accumulated postretirement benefit obligation	$ 48	$ (42)

Taking into account estimated employee future service, FirstEnergy expects to make the following pension benefit payments from plan assets and other benefit payments, net of the Medicare subsidy:

	Pension Benefits	Other Benefits
	(In millions)	
2008	$ 300	$ 83
2009	300	86
2010	307	90
2011	313	94
2012	322	95
Years 2013- 2017	1,808	495

4. STOCK-BASED COMPENSATION PLANS

FirstEnergy has four stock-based compensation programs: LTIP; EDCP; ESOP; and DCPD. FirstEnergy has also assumed responsibility for several stock-based plans through acquisitions. In 2001, FirstEnergy assumed responsibility for two stock-based plans as a result of its acquisition of GPU. No further stock-based compensation can be awarded under GPU's Stock Option and Restricted Stock Plan for MYR Group Inc. Employees (MYR Plan) or 1990 Stock Plan for Employees of GPU, Inc. and Subsidiaries (GPU Plan). All options and restricted stock under both plans have been converted into FirstEnergy options and restricted stock. Options under the GPU Plan became fully vested on November 7, 2001, and will expire on or before June 1, 2010.

Effective January 1, 2006, FirstEnergy adopted SFAS 123(R), which requires the expensing of stock-based compensation. Under SFAS 123(R), all share-based compensation cost is measured at the grant date based on the fair value of the award, and is recognized as an expense over the employee's requisite service period. FirstEnergy adopted the modified prospective method, under which compensation expense recognized in the year ended December 31, 2006 included the expense for all share-based payments granted prior to but not yet vested as of January 1, 2006. Results for prior periods were not restated.

Prior to the adoption of SFAS 123(R) on January 1, 2006, FirstEnergy's LTIP, EDCP, ESOP, and DCPD stock-based compensation programs were accounted for under the recognition and measurement principles of APB 25 and related interpretations. Under APB 25, no compensation expense was reflected in net income for stock options as all options granted under those plans have exercise prices equal to the market value of the underlying common stock on the respective grant dates, resulting in substantially no intrinsic value. The pro forma effects on net income for stock options were instead disclosed in a footnote to the financial statements. Under APB 25 and SFAS 123(R), compensation expense was recorded in the income statement for restricted stock, restricted stock units, performance shares and the EDCP and DCPD programs. No stock options have been granted since the third quarter of 2004. Consequently, the impact of adopting SFAS 123(R) was not material to FirstEnergy's net income and earnings per share in the three years ended December 31, 2007.

(A) LTIP

FirstEnergy's LTIP includes four stock-based compensation programs – restricted stock, restricted stock units, stock options, and performance shares. During 2005, FirstEnergy began issuing restricted stock units and reduced its use of stock options.

Under FirstEnergy's LTIP, total awards cannot exceed 29.1 million shares of common stock or their equivalent. Only stock options, restricted stock and restricted stock units have currently been designated to pay out in common stock, with vesting periods ranging from two months to ten years. Performance share awards are currently designated to be paid in cash rather than common stock and therefore do not count against the limit on stock-based awards. As of December 31, 2007, 9.3 million shares were available for future awards.

Restricted Stock and Restricted Stock Units

Eligible employees receive awards of FirstEnergy common stock or stock units subject to restrictions. Those restrictions lapse over a defined period of time or based on performance. Dividends are received on the restricted stock and are reinvested in additional shares. Restricted common stock grants under the LTIP were as follows:

	2007	2006	2005
Restricted common shares granted	77,388	229,271	356,200
Weighted average market price	$67.98	$53.18	$41.52
Weighted average vesting period (years)	4.61	4.47	5.4
Dividends restricted	Yes	Yes	Yes

Vesting activity for restricted common stock during the year was as follows:

Restricted Stock	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested as of January 1, 2007	629,482	$ 45.79
Nonvested as of December 31, 2007	639,657	48.69
Vested in 2007	67,063	65.02

FirstEnergy grants two types of restricted stock unit awards – discretionary-based and performance-based. With the discretionary-based, FirstEnergy grants the right to receive, at the end of the period of restriction, a number of shares of common stock equal to the number of restricted stock units set forth in each agreement. With performance-based, FirstEnergy grants the right to receive, at the end of the period of restriction, a number of shares of common stock equal to the number of restricted stock units set forth in the agreement subject to adjustment based on FirstEnergy's stock performance.

	2007	2006	2005
Restricted common share units granted	412,426	440,676	477,920
Weighted average vesting period (years)	3.22	3.32	3.32

Vesting activity for restricted stock units during the year was as follows:

Restricted Stock Units	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested as of January 1, 2007	887,794	$ 45.97
Nonvested as of December 31, 2007	1,208,780	51.09
Granted during 2007	412,426	62.25
Vested in 2007	10,603	62.87

Compensation expense recognized in 2007, 2006 and 2005 for restricted stock and restricted stock units was approximately $30 million, $17 million and $10 million, respectively.

Stock Options

Stock options were granted to eligible employees allowing them to purchase a specified number of common shares at a fixed grant price over a defined period of time. Stock option activities under FirstEnergy stock option programs for the past three years were as follows:

Stock Option Activities	Number of Options	Weighted Average Exercise Price
Balance, January 1, 2005	13,232,755	$ 32.40
(3,175,023 options exercisable)		29.07
Options granted	-	-
Options exercised	4,140,893	29.79
Options forfeited	225,606	34.37
Balance, December 31, 2005	8,866,256	33.57
(4,090,829 options exercisable)		31.97
Options granted	-	-
Options exercised	2,221,417	32.65
Options forfeited	26,550	33.36
Balance, December 31, 2006	6,618,289	33.88
(4,160,859 options exercisable)		32.85
Options granted	-	-
Options exercised	1,902,780	32.51
Options forfeited	9,575	38.39
Balance, December 31, 2007	4,705,934	34.42
(3,915,694 options exercisable)		33.55

Options outstanding by plan and range of exercise price as of December 31, 2007 were as follows:

		Options Outstanding			Options Exercisable	
Program	Range of Exercise Prices	Shares	Weighted Average Exercise Price	Remaining Contractual Life	Shares	Weighted Average Exercise Price
FE Plan	$19.31 - $29.87	1,682,609	$29.15	4.50	1,682,609	$29.15
	$30.17 - $39.46	3,004,290	$37.44	5.57	2,214,050	$36.96
GPU Plan	$23.75 - $35.92	19,035	$24.47	2.35	19,035	$24.27
Total		4,705,934	$34.42	5.17	3,915,694	$33.55

Prior to the adoption of SFAS 123(R) compensation expense for FirstEnergy stock options was based on intrinsic value, which equals any positive difference between FirstEnergy's common stock price on the option's grant date and the option's exercise price. The exercise prices of all stock options granted in prior years equaled the market price of FirstEnergy's common stock on the options' grant dates. If fair value accounting were applied to FirstEnergy's stock options, net income and earnings per share in 2005 would have been reduced as summarized below.

	2005
	(In millions, except per share amounts)
Net Income, as reported	$ 861
Add back compensation expense reported in net income, net of tax (based on APB 25)*	32
Deduct compensation expense based upon estimated fair value, net of tax*	(39)
Pro forma net income	$ 854
Earnings Per Share of Common Stock - Basic	
As Reported	$ 2.62
Pro Forma	$ 2.60
Diluted	
As Reported	$ 2.61
Pro Forma	$ 2.59

* Includes restricted stock, restricted stock units, stock options, performance shares, ESOP, EDCP and DCPD.

As noted above, FirstEnergy reduced its use of stock options beginning in 2005 and increased its use of performance-based, restricted stock units. FirstEnergy did not accelerate out-of-the-money options in anticipation of adopting SFAS 123(R) on January 1, 2006. As a result, all currently unvested stock options will vest by 2008. Compensation expense recognized for stock options during 2007 was approximately $1 million.

Performance Shares

Performance shares are share equivalents and do not have voting rights. The shares track the performance of FirstEnergy's common stock over a three-year vesting period. During that time, dividend equivalents are converted into additional shares. The final account value may be adjusted based on the ranking of FirstEnergy stock performance to a composite of peer companies. Compensation expense recognized for performance shares during 2007, 2006 and 2005 totaled approximately $20 million, $25 million and $7 million, respectively.

(B) ESOP

An ESOP Trust funded most of the matching contribution for FirstEnergy's 401(k) savings plan through December 31, 2007. All full-time employees eligible for participation in the 401(k) savings plan are covered by the ESOP. Between 1990 and 1991, the ESOP borrowed $200 million from OE and acquired 10,654,114 shares of OE's common stock (subsequently converted to FirstEnergy common stock) through market purchases. Dividends on ESOP shares were used to service the debt. Shares were released from the ESOP on a pro rata basis as debt service payments were made.

In determining the amount of borrowing under the ESOP, assumptions were made including the size and growth rate of FirstEnergy's workforce, earnings, dividends, and trading price of common stock. In 2005, the ESOP loan was refinanced ($66 million principal amount) and its term was extended by three years. In 2007, 2006 and 2005, 521,818 shares, 922,978 shares and 588,004 shares, respectively, were allocated to employees with the corresponding expense recognized based on the shares allocated method. All shares had been allocated as of December 31, 2007. Total ESOP-related compensation expense was calculated as follows:

	2007	2006	2005
		(In millions)	
Base compensation	$ 36	$ 50	$ 39
Dividends on common stock held by the ESOP and used to service debt	(11)	(11)	(10)
Net expense	$ 25	$ 39	$ 29

(C) EDCP

Under the EDCP, covered employees can direct a portion of their compensation, including annual incentive awards and/or long-term incentive awards, into an unfunded FirstEnergy stock account to receive vested stock units or into an unfunded retirement cash account. An additional 20% premium is received in the form of stock units based on the amount allocated to the FirstEnergy stock account. Dividends are calculated quarterly on stock units outstanding and are paid in the form of additional stock units. Upon withdrawal, stock units are converted to FirstEnergy shares. Payout typically occurs three years from the date of deferral; however, an election can be made in the year prior to payout to further defer shares into a retirement stock account that will pay out in cash upon retirement (see Note 3). Interest is calculated on the cash allocated to the cash account and the total balance will pay out in cash upon retirement. Of the 1.3 million EDCP stock units authorized, 606,659 stock units were available for future awards as of December 31, 2007. Compensation expense recognized on EDCP stock units was approximately $7 million in 2007 and approximately $5 million in 2006 and 2005, respectively.

(D) DCPD

Under the DCPD, directors can elect to allocate all or a portion of their cash retainers, meeting fees and chair fees to deferred stock or deferred cash accounts. If the funds are deferred into the stock account, a 20% match is added to the funds allocated. The 20% match and any appreciation on it are forfeited if the director leaves the Board within three years from the date of deferral for any reason other than retirement, disability, death, upon a change in control, or when a director is ineligible to stand for re-election. Compensation expense is recognized for the 20% match over the three-year vesting period. Directors may also elect to defer their equity retainers into the deferred stock account; however, they do not receive a 20% match on that deferral. DCPD expenses recognized in each of 2007, 2006 and 2005 were approximately $3 million. The net liability recognized for DCPD of $5 million as of December 31, 2007 and 2006 is included in the caption "retirement benefits" on the Consolidated Balance Sheets.

5. FAIR VALUE OF FINANCIAL INSTRUMENTS

(A) LONG-TERM DEBT AND OTHER LONG-TERM OBLIGATIONS

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

	2007		2006	
	Carrying Value	Fair Value	Carrying Value	Fair Value
		(In millions)		
Long-term debt	$ 10,891	$ 11,131	$ 10,321	$ 10,725
Subordinated debentures to affiliated trusts	-	-	103	105
	$ 10,891	$ 11,131	$ 10,424	$ 10,830

The fair values of long-term debt and other long-term obligations reflect 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 Companies' ratings.

(B) INVESTMENTS

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. Investments other than cash and cash equivalents include held-to-maturity securities and available-for-sale securities. The Companies and NGC periodically evaluate their 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.

FirstEnergy has assessed the impact of recent market developments, including a series of rating agency downgrades of subprime mortgage-related assets, on the value of the assets held in its nuclear decommissioning trusts. Based on this assessment, FirstEnergy believes that the fair value of its investments as of December 31, 2007 will not be materially affected by the subprime credit crisis due to their relatively small exposure to subprime assets.

Available-For-Sale Securities

The Companies and NGC hold debt and equity securities within their nuclear decommissioning trusts, nuclear fuel disposal trusts and NUG trusts. These trust investments are classified as available-for-sale with the fair value representing quoted market prices. FirstEnergy has no securities held for trading purposes.

The following table provides the carrying value, which approximates fair value, of investments in available-for-sale securities as of December 31, 2007 and 2006. The fair value was determined using the specific identification method.

	2007	2006
	(In millions)	
Debt securities:		
–Government obligations [1][2]	$ 851	$ 788
–Corporate debt securities	191	153
–Mortgage-backed securities	17	12
	1,059	953
Equity securities	1,355	1,284
	$ 2,414	$ 2,237

(1) Excludes $3 million and $5 million of cash in 2007 and 2006, respectively.
(2) Excludes $2 million of receivables and payables in 2006.

The following table summarizes the amortized cost basis, unrealized gains and losses and fair values of investments in available-for-sale securities as of December 31:

	2007				2006			
	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
				(In millions)				
Debt securities	$ 1,036	$ 27	$ 4	$ 1,059	$ 948	$ 10	$ 5	$ 953
Equity securities	995	360	-	1,355	952	332	-	1,284
	$ 2,031	$ 387	$ 4	$ 2,414	$ 1,900	$ 342	$ 5	$ 2,237

Proceeds from the sale of investments in available-for-sale securities, realized gains and losses on those sales, and interest and dividend income for the three years ended December 31, 2007 were as follows:

	2007	2006	2005
		(In millions)	
Proceeds from sales	$ 1,294	$ 1,651	$ 1,587
Realized gains	103	121	133
Realized losses	53	105	60
Interest and dividend income	80	70	62

Upon adoption of FSP SFAS 115-1 and SFAS 124-1, FirstEnergy began expensing unrealized losses on available-for-sale securities held in its nuclear decommissioning trusts since the trust arrangements, as they are currently defined, do not meet the required ability and intent to hold criteria in consideration of other-than-temporary impairment.

Unrealized gains applicable to OE's, TE's and the majority of NGC's decommissioning trusts are recognized in OCI in accordance with SFAS 115, as fluctuations in fair value will eventually impact earnings. The decommissioning trusts of JCP&L, Met-Ed and Penelec are subject to regulatory accounting in accordance with SFAS 71. Net unrealized gains and losses are recorded as regulatory assets or liabilities since the difference between investments held in trust and the decommissioning liabilities will be recovered from or refunded to customers.

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

Held-To-Maturity Securities

The following table provides the approximate fair value and related carrying amounts of investments in held-to-maturity securities, which excludes investments of $314 million and $323 million for 2007 and 2006, respectively, excluded by SFAS 107, "Disclosures about Fair Values of Financial Instruments", as of December 31:

	2007		2006	
	Carrying Value	Fair Value	Carrying Value	Fair Value
		(In millions)		
Lease obligations bonds	$ 717	$ 814	$ 811	$ 908
Debt securities	73	73	66	69
Notes receivable	45	43	70	67
Restricted funds	3	3	11	11
Equity securities	29	29	9	9
	$ 867	$ 962	$ 967	$ 1,064

The fair value of investments in lease obligation bonds is based on the present value of the cash inflows based on the yield to maturity. The maturity dates range from 2008 to 2017. The carrying value of the restricted funds is assumed to approximate market value. The fair value of notes receivable represents the present value of the cash inflows based on the yield to maturity. The yields assumed were based on financial instruments with similar characteristics and terms. The maturity dates range from 2008 to 2040.

The following table provides the amortized cost basis, unrealized gains and losses, and fair values of investments in held-to-maturity securities excluding the restricted funds and notes receivable as of December 31:

	2007				2006			
	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value	Cost Basis	Unrealized Gains	Unrealized Losses	Fair Value
				(In millions)				
Debt securities	$ 790	$ 97	$ -	$ 887	$ 877	$ 100	$ -	$ 977
Equity securities	29	-	-	29	9	-	-	9
	$ 819	$ 97	$ -	$ 916	$ 886	$ 100	$ -	$ 986

(C) DERIVATIVES

FirstEnergy is exposed to financial risks resulting from the fluctuation of interest rates, foreign currencies and commodity prices, including prices for electricity, natural gas, coal and energy transmission. To manage the volatility relating to these exposures, FirstEnergy uses a variety of derivative instruments, including forward contracts, options, futures contracts and swaps. The derivatives are used principally for hedging purposes. In addition to derivatives, FirstEnergy also enters into master netting agreements with certain third parties. FirstEnergy's Risk Policy Committee, comprised of members of senior management, provides general management oversight for risk management activities throughout FirstEnergy. They are responsible for promoting the effective design and implementation of sound risk management programs. They also oversee compliance with corporate risk management policies and established risk management practices.

FirstEnergy accounts for derivative instruments on its Consolidated Balance Sheet at their fair value unless they meet the normal purchase and normal sales criteria. Derivatives that meet that criteria are accounted for using traditional accrual accounting. The changes in the fair value of derivative instruments that do not meet the normal purchase and normal sales criteria are recorded as other expense, as AOCL, or as part of the value of the hedged item, depending on whether or not it is designated as part of a hedge transaction, the nature of the hedge transaction and hedge effectiveness.

FirstEnergy hedges anticipated transactions using cash flow hedges. Such transactions include hedges of anticipated electricity and natural gas purchases, capital assets denominated in foreign currencies and anticipated interest payments associated with future debt issues. Other than interest-related hedges, FirstEnergy's maximum hedge term is typically two years. The effective portions of all cash flow hedges are initially recorded in equity as other comprehensive income or loss and are subsequently included in net income as the underlying hedged commodities are delivered or interest payments are made. Gains and losses from any ineffective portion of cash flow hedges are included directly in earnings.

The net deferred losses of $75 million included in AOCL as of December 31, 2007, for derivative hedging activity, as compared to $58 million as of December 31, 2006, resulted from a net $33 million increase related to current hedging activity and a $16 million decrease due to net hedge losses reclassified to earnings during 2007. Based on current estimates, approximately $24 million (after tax) of the net deferred losses on derivative instruments in AOCL as of December 31, 2007 are expected to be reclassified to earnings during the next twelve months as hedged transactions occur. The fair value of these derivative instruments fluctuate from period to period based on various market factors.

FirstEnergy has entered into swaps that have been designated as fair value hedges of fixed-rate, long-term debt issues to protect against the risk of changes in the fair value of fixed-rate debt instruments due to lower interest rates. Swap maturities, call options, fixed interest rates received, and interest payment dates match those of the underlying debt obligations. During 2007, FirstEnergy unwound swaps with a total notional value of $500 million, for which it incurred $2 million in cash losses that will be recognized as interest expense over the remaining maturity of each hedged security. As of December 31, 2007, FirstEnergy had interest rate swaps with an aggregate notional value of $250 million and a fair value of $(3) million.

During 2007, FirstEnergy entered into several forward starting swap agreements (forward swaps) in order to hedge a portion of the consolidated interest rate risk associated with the anticipated issuances of fixed-rate, long-term debt securities for one or more of its subsidiaries as outstanding debt matures during 2008. These derivatives are treated as cash flow hedges, protecting against the risk of changes in future interest payments resulting from changes in benchmark U.S. Treasury rates between the date of hedge inception and the date of the debt issuance. During 2007, FirstEnergy terminated swaps with a notional value of $2.5 billion for which it paid $30 million, $1.6 million of which was deemed ineffective and recognized in current period earnings. FirstEnergy will recognize the remaining $28 million loss over the life of the associated future debt. As of December 31, 2007, FirstEnergy had forward swaps with an aggregate notional amount of $400 million and a fair value of $(3) million.

6. LEASES

FirstEnergy leases certain generating facilities, office space and other property and equipment under cancelable and noncancelable leases.

On July 13, 2007, FGCO completed a sale and leaseback transaction for its 93.825% undivided interest in Bruce Mansfield Unit 1, representing 779 MW of net demonstrated capacity. The purchase price of approximately $1.329 billion (net after-tax proceeds of approximately $1.2 billion) for the undivided interest was funded through a combination of equity investments by affiliates of AIG Financial Products Corp. and Union Bank of California, N.A. in six lessor trusts and proceeds from the sale of $1.135 billion aggregate principal amount of 6.85% pass through certificates due 2034. A like principal amount of secured notes maturing June 1, 2034 were issued by the lessor trusts to the pass through trust that issued and sold the certificates. The lessor trusts leased the undivided interest back to FGCO for a term of approximately 33 years under substantially identical leases. FES has unconditionally and irrevocably guaranteed all of FGCO's obligations under each of the leases. This transaction, which is classified as an operating lease under GAAP for FES and FirstEnergy, generated tax capital gains of approximately $742 million, all of which were offset by existing tax capital loss carryforwards. Accordingly, FirstEnergy reduced its tax loss carryforward valuation allowances in the third quarter of 2007, with a corresponding reduction to goodwill (see Note 2(E)).

In 1987, OE sold portions of its ownership interests in Perry Unit 1 and Beaver Valley Unit 2 and entered into operating leases on the portions sold for basic lease terms of approximately 29 years. In that same year, CEI and TE also sold portions of their ownership interests in Beaver Valley Unit 2 and Bruce Mansfield Units 1, 2 and 3 and entered into similar operating leases for lease terms of approximately 30 years. During the terms of their respective leases, OE, CEI and TE continue to be responsible, to the extent of their leasehold interests, for costs associated with the units including construction expenditures, operation and maintenance expenses, insurance, nuclear fuel, property taxes and decommissioning. They have the right, at the expiration of the respective basic lease terms, to renew their respective leases. They also have the right to purchase the facilities at the expiration of the basic lease term or any renewal term at a price equal to the fair market value of the facilities. The basic rental payments are adjusted when applicable federal tax law changes.

Effective October 16, 2007 CEI and TE assigned their leasehold interests in the Bruce Mansfield Plant to FGCO. FGCO assumed all of CEI's and TE's obligations arising under those leases. FGCO subsequently transferred the Unit 1 portion of these leasehold interests, as well as FGCO's leasehold interests under its July 13, 2007 Bruce Mansfield Unit 1 sale and leaseback transaction, to a newly formed wholly-owned subsidiary on December 17, 2007. The subsidiary assumed all of the lessee obligations associated with the assigned interests. However, CEI and TE remain primarily liable on the 1987 leases and related agreements. FGCO remains primarily liable on the 2007 leases and related agreements, and FES remains primarily liable as a guarantor under the related 2007 guarantees, as to the lessors and other parties to the respective agreements.

Rentals for capital and operating leases for the three years ended December 31, 2007 are summarized as follows:

	2007	2006	2005
		(In millions)	
Operating leases			
Interest element	$ 180	$ 160	$ 171
Other	196	190	162
Capital leases			
Interest element	-	1	1
Other	1	2	2
Total rentals	$ 377	$ 353	$ 336

Established by OE in 1996, PNBV purchased a portion of the lease obligation bonds issued on behalf of lessors in OE's Perry Unit 1 and Beaver Valley Unit 2 sale and leaseback transactions. Similarly, CEI and TE established Shippingport in 1997 to purchase the lease obligation bonds issued on behalf of lessors in their Bruce Mansfield Units 1, 2 and 3 sale and leaseback transactions. The PNBV and Shippingport arrangements effectively reduce lease costs related to those transactions (see Note 7).

The future minimum lease payments as of December 31, 2007 are:

	Capital Leases	Operating Leases: Lease Payments	Operating Leases: Capital Trusts	Operating Leases: Net
		(In millions)		
2008	$ 1	$ 419	$ 103	$ 316
2009	1	424	107	317
2010	1	425	116	309
2011	1	417	116	301
2012	1	457	125	332
Years thereafter	1	3,622	384	3,238
Total minimum lease payments	6	$ 5,764	$ 951	$ 4,813
Executory costs	-			
Net minimum lease payments	6			
Interest portion	1			
Present value of net minimum lease payments	5			
Less current portion	1			
Noncurrent portion	$ 4			

FirstEnergy has recorded above-market lease liabilities for Beaver Valley Unit 2 and the Bruce Mansfield Plant associated with the 1997 merger between OE and Centerior. The total above-market lease obligation of $722 million associated with Beaver Valley Unit 2 is being amortized on a straight-line basis through the end of the lease term in 2017 (approximately $37 million per year). The total above-market lease obligation of $755 million associated with the Bruce Mansfield Plant is being amortized on a straight-line basis through the end of 2016 (approximately $46 million per year). As of December 31, 2007, the above-market lease liabilities for Beaver Valley Unit 2 and the Bruce Mansfield Plant totaled $746 million, of which $83 million is classified in the caption "other current liabilities."

7. VARIABLE INTEREST ENTITIES

FIN 46R addresses the consolidation of VIEs, including special-purpose entities, that are not controlled through voting interests or in which the equity investors do not bear the entity's residual economic risks and rewards. FirstEnergy and its subsidiaries consolidate VIEs when they are determined to be the VIE's primary beneficiary as defined by FIN 46R.

Trusts

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

PNBV was established to purchase a portion of the lease obligation bonds issued in connection with OE's 1987 sale and leaseback of its interests in the Perry Plant and Beaver Valley Unit 2. OE used debt and available funds to purchase the notes issued by PNBV. Ownership of PNBV includes a 3% equity interest by an unaffiliated third party and a 3% equity interest held by OES Ventures, a wholly owned subsidiary of OE. Shippingport was established to purchase all of the lease obligation bonds issued in connection with CEI's and TE's Bruce Mansfield Plant sale and leaseback transaction in 1987. CEI and TE used debt and available funds to purchase the notes issued by Shippingport.

Loss Contingencies

FES and the Ohio Companies are exposed to losses under their applicable sale-leaseback agreements upon the occurrence of certain contingent events that each company considers unlikely to occur. The maximum exposure under these provisions represents the net amount of casualty value payments due upon the occurrence of specified casualty events that render the applicable plant worthless. Net discounted lease payments would not be payable if the casualty loss payments are made. The following table shows each company's net exposure to loss based upon the casualty value provisions mentioned above:

	Maximum Exposure	Discounted Lease Payments, net	Net Exposure
		(in millions)	
FES	$ 1,338	$ 1,198	$ 140
OE	837	610	227
CEI	753	85	668
TE	753	449	304

Effective October 16, 2007, CEI and TE assigned their leasehold interests in the Bruce Mansfield Plant under their 1987 sale and leaseback transactions to FGCO. FGCO assumed all of CEI's and TE's obligations arising under those leases. FGCO subsequently transferred the Unit 1 portion of these leasehold interests, as well as FGCO's leasehold interests under its July 13, 2007 Bruce Mansfield Unit 1 sale and leaseback transaction discussed above, to a newly formed wholly-owned subsidiary on December 17, 2007. The subsidiary assumed all of the lessee obligations associated with the assigned interests. However, CEI and TE remain primarily liable on the 1987 leases and related agreements. FGCO remains primarily liable on the 2007 leases and related agreements, and FES remains primarily liable as a guarantor under the related 2007 guarantees, as to the lessors and other parties to the respective agreements. These assignments terminate automatically upon the termination of the underlying leases.

Power Purchase Agreements

In accordance with FIN 46R, FirstEnergy evaluated its power purchase agreements and determined that certain NUG entities may be VIEs to the extent they own a plant that sells substantially all of its output to the Companies and the contract price for power is correlated with the plant's variable costs of production. FirstEnergy, through its subsidiaries JCP&L, Met-Ed and Penelec, maintains approximately 30 long-term power purchase agreements with NUG entities. The agreements were entered into pursuant to the Public Utility Regulatory Policies Act of 1978. FirstEnergy was not involved in the creation of, and has no equity or debt invested in, these entities.

FirstEnergy has determined that for all but eight of these entities, neither JCP&L, Met-Ed nor Penelec have variable interests in the entities or the entities are governmental or not-for-profit organizations not within the scope of FIN 46R. JCP&L, Met-Ed or Penelec may hold variable interests in the remaining eight entities, which sell their output at variable prices that correlate to some extent with the operating costs of the plants. As required by FIN 46R, FirstEnergy periodically requests from these eight entities the information necessary to determine whether they are VIEs or whether JCP&L, Met-Ed or Penelec is the primary beneficiary. FirstEnergy has been unable to obtain the requested information, which in most cases was deemed by the requested entity to be proprietary. As such, FirstEnergy applied the scope exception that exempts enterprises unable to obtain the necessary information to evaluate entities under FIN 46R.

Since FirstEnergy has no equity or debt interests in the NUG entities, its maximum exposure to loss relates primarily to the above-market costs it incurs for power. FirstEnergy expects any above-market costs it incurs to be recovered from customers. As of December 31, 2007, the net above-market loss liability projected for these eight NUG agreements was approximately $74 million. Purchased power costs from these entities during 2007, 2006 and 2005 were $177 million, $171 million, and $180 million, respectively.

8. DISCONTINUED OPERATIONS

In March 2005, FirstEnergy sold 51% of its interest in FirstCom, resulting in an after-tax gain of $4 million. FirstEnergy accounted for its remaining 31.85% interest in FirstCom on the equity basis until July 2007 when FirstEnergy's ownership interest decreased to approximately 15% and FirstEnergy began accounting for its investment under the cost method.

In 2006, FirstEnergy sold its remaining FSG subsidiaries (Roth Bros., Hattenbach, Dunbar, Edwards and RPC) for an aggregate net after-tax gain of $2.2 million. Hattenbach, Dunbar, Edwards, and RPC were accounted for as discontinued operations as of December 31, 2006; Roth Bros. did not meet the criteria for that classification as of December 31, 2006.

In 2005, three FSG subsidiaries, Elliott-Lewis, Spectrum Control Systems and L.H. Cranston & Sons, and MYR's Power Piping Company subsidiary were sold resulting in an after-tax gain of $13 million. All of these sales, except the Spectrum Control Systems, met the criteria for discontinued operations at December 31, 2005. On March 31, 2005, FES sold its natural gas business for an after-tax gain of $5 million and was included in discontinued operations at December 31, 2005.

In December 2005, MYR had qualified as an asset held for sale but did not meet the criteria to be classified as discontinued operations. As required by SFAS 142, the goodwill of MYR was tested for impairment, resulting in a non-cash charge of $9 million in the fourth quarter of 2005 (see Note 2(E)). The carrying amounts of MYR's assets and liabilities as of December 31, 2005 held for sale were not material and had not been classified as assets held for sale on FirstEnergy's Consolidated Balance Sheet.

In March 2006, FirstEnergy sold 60% of its interest in MYR for an after-tax gain of $0.2 million. In June 2006, as part of the March agreement, FirstEnergy sold an additional 1.67% interest. As a result of the March sale, FirstEnergy deconsolidated MYR in the first quarter of 2006 and accounted for its remaining 38.33% interest under the equity method of accounting for investments. In the fourth quarter of 2006, FirstEnergy sold its remaining MYR interest for an after-tax gain of $8.6 million. The income for the period that MYR was accounted for as an equity method investment has not been included in discontinued operations; however, results for all reporting periods prior to the initial sale in March 2006, including the gain on the sale, were reported as discontinued operations.

Revenues associated with discontinued operations were $225 million and $845 million in 2006 and 2005, respectively. The following table summarizes the net income operating results of discontinued operations for 2006 and 2005:

	2006	2005
	(In millions)	
Income (loss) before income taxes	$ (4)	$ (1)
Income tax expense	(2)	(5)
Gain (loss) on sale, net of tax	2	18
Income (loss) from discontinued operations	$ (4)	$ 12

9. TAXES

Income Taxes

FirstEnergy 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 loss carryforwards and the amounts recognized 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 temporary tax and accounting basis differences and tax credit carryforward items are recognized at the statutory income tax rates in effect when the liabilities are expected to be paid. Deferred tax assets are recognized based on income tax rates expected to be in effect when they are settled. Details of income taxes for the three years ended December 31, 2007 are shown below:

For the Years Ended December 31,	2007	2006	2005
		(In millions)	
PROVISION FOR INCOME TAXES:			
Currently payable-			
Federal	$ 706	$ 519	$ 452
State	187	116	142
	893	635	594
Deferred, net-			
Federal	22	147	72
State	(18)	28	110
	4	175	182
Investment tax credit amortization	(14)	(15)	(27)
Total provision for income taxes	$ 883	$ 795	$ 749
RECONCILIATION OF FEDERAL INCOME TAX EXPENSE AT STATUTORY RATE TO TOTAL PROVISION FOR INCOME TAXES:			
Book income before provision for income taxes	$ 2,192	$ 2,053	$ 1,628
Federal income tax expense at statutory rate	$ 767	$ 719	$ 569
Increases (reductions) in taxes resulting from-			
Amortization of investment tax credits	(14)	(15)	(27)
State income taxes, net of federal income tax benefit	110	94	165
Penalties	-	-	14
Amortization of tax regulatory assets	8	2	38
Preferred stock dividends	-	5	5
Other, net	12	(10)	(15)
Total provision for income taxes	$ 883	$ 795	$ 749

Accumulated deferred income taxes as of December 31, 2007 and 2006 are as follows:

As of December 31,	2007	2006
	(In millions)	
Property basis differences	$ 2,502	$ 2,595
Regulatory transition charge	706	457
Customer receivables for future income taxes	149	141
Deferred customer shopping incentive	263	219
Deferred sale and leaseback gain	(536)	(86)
Nonutility generation costs	(90)	(122)
Unamortized investment tax credits	(44)	(50)
Other comprehensive income	(68)	(260)
Retirement benefits	(9)	10
Lease market valuation liability	(283)	(331)
Oyster Creek securitization (Note 11(C))	149	162
Loss carryforwards	(44)	(426)
Loss carryforward valuation reserve	31	415
Asset retirement obligations	35	45
Nuclear decommissioning	(169)	(116)
All other	79	87
Net deferred income tax liability	$ 2,671	$ 2,740

On January 1, 2007, FirstEnergy adopted FIN 48, which provides guidance for accounting for uncertainty in income taxes in a company's financial statements in accordance with SFAS 109. This interpretation prescribes a financial statement recognition threshold and measurement attribute for tax positions taken or expected to be taken on a company's tax return. FIN 48 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 is a two-step process. The first step is to determine if it is more likely than not that a tax position will be sustained upon examination, based on the merits of the position, and should therefore be recognized. The second step is to measure a tax position that meets the more likely than not recognition threshold to determine the amount of income tax benefit to recognize in the financial statements.

As of January 1, 2007, the total amount of FirstEnergy's unrecognized tax benefits was $268 million. FirstEnergy recorded a $2.7 million cumulative effect adjustment to the January 1, 2007 balance of retained earnings to increase reserves for uncertain tax positions. Of the total amount of unrecognized income tax benefits, $92 million would favorably affect FirstEnergy's effective tax rate upon recognition. The majority of items that would not have affected the effective tax rate resulted from purchase accounting adjustments that would reduce goodwill upon recognition through December 31, 2008.

A reconciliation of the change in the unrecognized tax benefits for the year ended December 31, 2007 is as follows:

	(In millions)
Balance as of January 1, 2007	$ 268
Increase for tax positions related to the current year	1
Increase for tax positions related to prior years	3
Balance as of December 31, 2007	$ 272

As of December 31, 2007, FirstEnergy expects that $7 million of the unrecognized benefits will be resolved within the next twelve months and is included in the caption "accrued taxes," with the remaining $265 million included in the caption "other non-current liabilities" on the Consolidated Balance Sheets.

FIN 48 also requires companies to recognize interest expense or income related to uncertain tax positions. That amount is computed by applying the applicable statutory interest rate to the difference between the tax position recognized in accordance with FIN 48 and the amount previously taken or expected to be taken on the tax return. FirstEnergy includes net interest and penalties in the provision for income taxes, consistent with its policy prior to implementing FIN 48. During the years ended December 31, 2007, 2006 and 2005, FirstEnergy recognized net interest expense of approximately $19 million, $9 million and $6 million, respectively. The cumulative net interest accrued as of December 31, 2007 and 2006 was $53 million and $34 million, respectively.

FirstEnergy has tax returns that are under review at the audit or appeals level by the IRS and state tax authorities. All state jurisdictions are open from 2001-2006. The IRS began reviewing returns for the years 2001-2003 in July 2004 and several items are under appeal. The federal audit for years 2004 and 2005 began in June 2006 and is not expected to close before December 2008. The IRS began auditing the year 2006 in April 2006 and the year 2007 in February 2007 under its Compliance Assurance Process experimental program. Neither audits are expected to close before December 2008. Management believes that adequate reserves have been recognized and final settlement of these audits is not expected to have a material adverse effect on FirstEnergy's financial condition or results of operations.

On July 13, 2007, FGCO completed a sale and leaseback transaction for its 93.825% undivided interest in Bruce Mansfield Unit 1, representing 779 MW of net demonstrated capacity (see Note 6). This transaction generated tax capital gains of approximately $742 million, all of which were offset by existing tax capital loss carryforwards. Accordingly, FirstEnergy reduced its tax loss carryforward valuation allowance in the third quarter of 2007, with a corresponding reduction to goodwill (see Note 2(E)).

FirstEnergy has pre-tax net operating loss carryforwards for state and local income tax purposes of approximately $1.156 billion of which $199 million is expected to be utilized. The associated deferred tax assets are $13 million. These losses expire as follows:

Expiration Period		Amount (In millions)
2008-2012	$	331
2013-2017		16
2018-2022		462
2023-2027		347
	$	1,156

General Taxes

Details of general taxes for the three years ended December 31, 2007 are shown below:

For the Years Ended December 31,		2007		2006 (In millions)		2005
GENERAL TAXES:						
Real and personal property	$	237	$	222	$	222
Kilowatt-hour excise		250		241		244
State gross receipts		175		159		151
Social security and unemployment		87		83		79
Other		5		15		17
Total general taxes	$	754	$	720	$	713

Commercial Activity Tax

On June 30, 2005, tax legislation was enacted in the State of Ohio that created a new CAT tax, which is based on qualifying "taxable gross receipts" and does not consider any expenses or costs incurred to generate such receipts, except for items such as cash discounts, returns and allowances, and bad debts. The CAT tax was effective July 1, 2005, and replaces the Ohio income-based franchise tax and the Ohio personal property tax. The CAT tax is phased-in while the current income-based franchise tax is phased-out over a five-year period at a rate of 20% annually, beginning with the year ended 2005, and the personal property tax is phased-out over a four-year period at a rate of approximately 25% annually, beginning with the year ended 2005. During the phase-out period the Ohio income-based franchise tax was or will be computed consistent with the prior tax law, except that the tax liability as computed was multiplied by 80% in 2005; 60% in 2006; 40% in 2007 and 20% in 2008, therefore eliminating the current income-based franchise tax over a five-year period. As a result of the new tax structure, all net deferred tax benefits that were not expected to reverse during the five-year phase-in period were written-off as of June 30, 2005.

The increase to income taxes associated with the adjustment to net deferred taxes in 2005 is summarized below (in millions):

OE	$	32
CEI		4
TE		18
Other FirstEnergy subsidiaries		(2)
Total FirstEnergy	$	52

Income tax expenses were reduced (increased) during 2005 by the initial phase-out of the Ohio income-based franchise tax and phase-in of the CAT tax as summarized below (in millions):

OE	$	3
CEI		5
TE		1
Other FirstEnergy subsidiaries		(3)
Total FirstEnergy	$	6

10. REGULATORY MATTERS

(A) RELIABILITY INITIATIVES

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. The proposed enhancements were divided into two groups: enhancements that were to be completed in 2004; and enhancements that were to be completed after 2004. In 2004, FirstEnergy completed all of the enhancements that were recommended for completion in 2004. Subsequently, FirstEnergy has worked systematically to complete all of the enhancements that were identified for completion after 2004, and FirstEnergy expects to complete this work prior to the summer of 2008. The FERC and the other affected government agencies and reliability entities may review FirstEnergy's work and, on the basis of any such review, may recommend additional enhancements in the future, which could require additional, material expenditures.

As a result of outages experienced in JCP&L's service area in 2002 and 2003, the NJBPU performed a review of JCP&L's service reliability. On June 9, 2004, the NJBPU approved a stipulation that addresses a third-party consultant's recommendations on appropriate courses of action necessary to ensure system-wide reliability. The stipulation incorporates the consultant's focused audit of, and recommendations regarding, JCP&L's Planning and Operations and Maintenance programs and practices. On June 1, 2005, the consultant completed his work and issued his final report to the NJBPU. On July 14, 2006, JCP&L filed a comprehensive response to the consultant's report with the NJBPU. JCP&L will complete the remaining substantive work described in the stipulation in 2008. JCP&L continues to file compliance reports with the NJBPU reflecting JCP&L's activities associated with implementing the stipulation.

In 2005, Congress amended the Federal Power Act to provide for federally-enforceable mandatory reliability standards. The mandatory reliability standards apply to the bulk power system and impose certain operating, record-keeping and reporting requirements on the Companies and ATSI. The NERC is charged with establishing and enforcing these reliability standards, although it has delegated day-to-day implementation and enforcement of its responsibilities to eight regional entities, including the Reliabilty*First* Corporation. All of FirstEnergy's facilities are located within the Reliabilty*First* region. FirstEnergy actively participates in the NERC and Reliabilty*First* stakeholder processes, and otherwise monitors and manages its companies in response to the ongoing development, implementation and enforcement of the reliability standards.

FirstEnergy believes that it is in compliance with all currently-effective and enforceable reliability standards. Nevertheless, it is clear that NERC, Reliabilty*First* and the FERC will continue to refine existing reliability standards as well as to develop and adopt new reliability standards. The financial impact of complying with new or amended standards cannot be determined at this time. However, the 2005 amendments to the Federal Power Act provide that all prudent costs incurred to comply with the new reliability standards be recovered in rates. Still, any future inability on FirstEnergy's part to comply with the reliability standards for its bulk power system could have a material adverse effect on its financial condition, results of operations and cash flows.

In April 2007, Reliability*First* performed a routine compliance audit of FirstEnergy's bulk-power system within the Midwest ISO region and found it to be in full compliance with all audited reliability standards. Similarly, Reliability*First* has scheduled a compliance audit of FirstEnergy's bulk-power system within the PJM region in 2008. FirstEnergy currently does not expect any material adverse financial impact as a result of these audits.

(B) OHIO

On September 9, 2005, the Ohio Companies filed their RCP with the PUCO. The filing included a stipulation and supplemental stipulation with several parties agreeing to the provisions set forth in the plan. On January 4, 2006, the PUCO issued an order which approved the stipulations clarifying certain provisions. Several parties subsequently filed appeals to the Supreme Court of Ohio in connection with certain portions of the approved RCP. In its order, the PUCO authorized the Ohio Companies to recover certain increased fuel costs through a fuel rider, and to defer certain other increased fuel costs to be incurred from January 1, 2006 through December 31, 2008, including interest on the deferred balances. The order also provided for recovery of the deferred costs over a 25-year period through distribution rates, which are expected to be effective on January 1, 2009 for OE and TE, and approximately May 2009 for CEI. Through December 31, 2007, the deferred fuel costs, including interest, were $111 million, $76 million and $33 million for OE, CEI and TE, respectively.

On August 29, 2007, the Supreme Court of Ohio concluded that the PUCO violated a provision of the Ohio Revised Code by permitting the Ohio Companies "to collect deferred increased fuel costs through future distribution rate cases, or to alternatively use excess fuel-cost recovery to reduce deferred distribution-related expenses" because fuel costs are a component of generation service, not distribution service, and permitting recovery of deferred fuel costs through distribution rates constituted an impermissible subsidy. The Court remanded the matter to the PUCO for further consideration consistent with the Court's Opinion on this issue and affirmed the PUCO's order in all other respects. On September 10, 2007 the Ohio Companies filed an Application with the PUCO that requested the implementation of two generation-related fuel cost riders to collect the increased fuel costs that were previously authorized to be deferred. The Ohio Companies requested the riders to become effective in October 2007 and end in December 2008, subject to reconciliation that would be expected to continue through the first quarter of 2009. On January 9, 2008 the PUCO approved the Ohio Companies' proposed fuel cost rider to recover increased fuel costs to be incurred commencing January 1, 2008 through December 31, 2008, which is expected to be approximately $167 million. The fuel cost rider became effective January 11, 2008 and will be adjusted and reconciled quarterly. In addition, the PUCO ordered the Ohio Companies to file a separate application for an alternate recovery mechanism to collect the 2006 and 2007 deferred fuel costs. On February 8, 2008, the Ohio Companies filed an application proposing to recover $220 million of deferred fuel costs and carrying charges for 2006 and 2007 pursuant to a separate fuel rider, with alternative options for the recovery period ranging from five to twenty-five years. This second application is currently pending before the PUCO.

The Ohio Companies recover all MISO transmission and ancillary service related costs incurred through a reconcilable rider that is updated annually on July 1. The riders that became effective on July 1, 2007, represent an increase over the amounts collected through the 2006 riders of approximately $64 million annually. If it is subsequently determined by the PUCO that adjustments to the riders as filed are necessary, such adjustments, with carrying costs, will be incorporated into the 2008 transmission rider filing.

The Ohio Companies filed an application and rate request for an increase in electric distribution rates with the PUCO on June 7, 2007. The requested increase is expected to be more than offset by the elimination or reduction of transition charges at the time the rates go into effect and would result in lowering the overall non-generation portion of the average electric bill for most Ohio customers. The distribution rate increases reflect capital expenditures since the Ohio Companies' last distribution rate proceedings, increases in operation and maintenance expenses and recovery of regulatory assets that were authorized in prior cases. On August 6, 2007, the Ohio Companies updated their filing supporting a distribution rate increase of $332 million. On December 4, 2007, the PUCO Staff issued its Staff Reports containing the results of their investigation into the distribution rate request. In its reports, the PUCO Staff recommended a distribution rate increase in the range of $161 million to $180 million, with $108 million to $127 million for distribution revenue increases and $53 million for recovery of costs deferred under prior cases. This amount excludes the recovery of deferred fuel costs, whose recovery is now being sought in a separate proceeding before the PUCO, discussed above. On January 3, 2008, the Ohio Companies and intervening parties filed objections to the Staff Reports and on January 10, 2008, the Ohio Companies filed supplemental testimony. Evidentiary hearings began on January 29, 2008 and continued through February 2008. During the evidentiary hearings, the PUCO Staff submitted testimony decreasing their recommended revenue increase to a range of $114 million to $132 million. Additionally, in testimony submitted on February 11, 2008, the PUCO Staff adopted a position regarding interest deferred pursuant to the RCP that, if upheld by the PUCO, would result in the write-off of approximately $13 million of interest costs deferred through December 31, 2007 ($0.03 per share of common stock). The PUCO is expected to render its decision during the second or third quarter of 2008. The new rates would become effective January 1, 2009 for OE and TE, and approximately May 2009 for CEI.

On July 10, 2007, the Ohio Companies filed an application with the PUCO requesting approval of a comprehensive supply plan for providing retail generation service to customers who do not purchase electricity from an alternative supplier, beginning January 1, 2009. The proposed competitive bidding process would average the results of multiple bidding sessions conducted at different times during the year. The final price per kilowatt-hour would reflect an average of the prices resulting from all bids. In their filing, the Ohio Companies offered two alternatives for structuring the bids, either by customer class or a "slice-of-system" approach. A slice-of-system approach would require the successful bidder to be responsible for supplying a fixed percentage of the utility's total load notwithstanding the customer's classification. The proposal provides the PUCO with an option to phase in generation price increases for residential tariff groups who would experience a change in their average total price of 15 percent or more. The PUCO held a technical conference on August 16, 2007 regarding the filing. Initial and reply comments on the proposal were filed by various parties in September and October, 2007, respectively. The proposal is currently pending before the PUCO.

On September 25, 2007, the Ohio Governor's proposed energy plan was officially introduced into the Ohio Senate. The bill proposes to revise state energy policy to address electric generation pricing after 2008, establish advanced energy portfolio standards and energy efficiency standards, and create GHG emissions reporting and carbon control planning requirements. The bill also proposes to move to a "hybrid" system for determining rates for default service in which electric utilities would provide regulated generation service unless they satisfy a statutory burden to demonstrate the existence of a competitive market for retail electricity. The Senate Energy & Public Utilities Committee conducted hearings on the bill and received testimony from interested parties, including the Governor's Energy Advisor, the Chairman of the PUCO, consumer groups, utility executives and others. Several proposed amendments to the bill were submitted, including those from Ohio's investor-owned electric utilities. A substitute version of the bill, which incorporated certain of the proposed amendments, was introduced into the Senate Energy & Public Utilities Committee on October 25, 2007 and was passed by the Ohio Senate on October 31, 2007. The bill as passed by the Senate is now being considered by the House Public Utilities Committee, which has conducted hearings on the bill. Testimony has been received from interested parties, including the Chairman of the PUCO, consumer groups, utility executives and others. At this time, FirstEnergy cannot predict the outcome of this process nor determine the impact, if any, such legislation may have on its operations or those of the Ohio Companies.

(C) PENNSYLVANIA

Met-Ed and Penelec have been purchasing a portion of their PLR and default service requirements from FES through a partial requirements wholesale power sales agreement and various amendments. Based on the outcome of the 2006 comprehensive transition rate filing, as described below, Met-Ed, Penelec and FES agreed to restate the partial requirements power sales agreement effective January 1, 2007. The restated agreement incorporates the same fixed price for residual capacity and energy supplied by FES as in the prior arrangements between the parties, and automatically extends for successive one year terms unless any party gives 60 days' notice prior to the end of the year. The restated agreement also allows Met-Ed and Penelec to sell the output of NUG energy to the market and requires FES to provide energy at fixed prices to replace any NUG energy sold to the extent needed for Met-Ed and Penelec to satisfy their PLR and default service obligations. The fixed price under the restated agreement is expected to remain below wholesale market prices during the term of the agreement.

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

Met-Ed and Penelec made a comprehensive transition rate filing with the PPUC on April 10, 2006 to address a number of transmission, distribution and supply issues. If Met-Ed's and Penelec's preferred approach involving accounting deferrals had been approved, annual revenues would have increased by $216 million and $157 million, respectively. That filing included, among other things, a request to charge customers for an increasing amount of market-priced power procured through a CBP as the amount of supply provided under the then existing FES agreement was to be phased out. Met-Ed and Penelec also requested approval of a January 12, 2005 petition for the deferral of transmission-related costs incurred during 2006. In this rate filing, Met-Ed and Penelec requested recovery of annual transmission and related costs incurred on or after January 1, 2007, plus the amortized portion of 2006 costs over a ten-year period, along with applicable carrying charges, through an adjustable rider. Changes in the recovery of NUG expenses and the recovery of Met-Ed's non-NUG stranded costs were also included in the filing. On May 4, 2006, the PPUC consolidated the remand of the FirstEnergy and GPU merger proceeding, related to the quantification and allocation of merger savings, with the comprehensive transition rate filing case.

The PPUC entered its opinion and order in the comprehensive rate filing proceeding on January 11, 2007. The order approved the recovery of transmission costs, including the transmission-related deferral for January 1, 2006 through January 10, 2007, and determined that no merger savings from prior years should be considered in determining customers' rates. The request for increases in generation supply rates was denied as were the requested changes to NUG expense recovery and Met-Ed's non-NUG stranded costs. The order decreased Met-Ed's and Penelec's distribution rates by $80 million and $19 million, respectively. These decreases were offset by the increases allowed for the recovery of transmission costs. Met-Ed's and Penelec's request for recovery of Saxton decommissioning costs was granted and, in January 2007, Met-Ed and Penelec recognized income of $15 million and $12 million, respectively, to establish regulatory assets for those previously expensed decommissioning costs. Overall rates increased by 5.0% for Met-Ed ($59 million) and 4.5% for Penelec ($50 million). Met-Ed and Penelec filed a Petition for Reconsideration on January 26, 2007, on the issues of consolidated tax savings and rate of return on equity. Other parties filed Petitions for Reconsideration on transmission (including congestion), transmission deferrals and rate design issues. On March 1, 2007, the PPUC issued three orders: (1) a tentative order regarding the reconsideration by the PPUC of its own order; (2) an order denying the Petitions for Reconsideration of Met-Ed, Penelec and the OCA and denying in part and accepting in part the MEIUG's and PICA's Petition for Reconsideration; and (3) an order approving the compliance filing. Comments to the PPUC for reconsideration of its order were filed on March 8, 2007, and the PPUC ruled on the reconsideration on April 13, 2007, making minor changes to rate design as agreed upon by Met-Ed, Penelec and certain other parties.

On March 30, 2007, MEIUG and PICA filed a Petition for Review with the Commonwealth Court of Pennsylvania asking the court to review the PPUC's determination on transmission (including congestion) and the transmission deferral. Met-Ed and Penelec filed a Petition for Review on April 13, 2007 on the issues of consolidated tax savings and the requested generation rate increase. The OCA filed its Petition for Review on April 13, 2007, on the issues of transmission (including congestion) and recovery of universal service costs from only the residential rate class. From June through October 2007, initial responsive and reply briefs were filed by various parties. Oral arguments are expected to take place on April 7, 2008. If Met-Ed and Penelec do not prevail on the issue of congestion, it could have a material adverse effect on the results of operations of Met-Ed, Penelec and FirstEnergy.

As of December 31, 2007, Met-Ed's and Penelec's unrecovered regulatory deferrals pursuant to the 2006 comprehensive transition rate case, the 1998 Restructuring Settlement (including the Phase 2 proceedings) and the FirstEnergy/GPU Merger Settlement Stipulation were $512 million and $55 million, respectively. During the PPUC's annual audit of Met-Ed's and Penelec's NUG stranded cost balances in 2006, it noted a modification to the NUG purchased power stranded cost accounting methodology made by Met-Ed and Penelec. On August 18, 2006, a PPUC order was entered requiring Met-Ed and Penelec to reflect the deferred NUG cost balances as if the stranded cost accounting methodology modification had not been implemented. As a result of this PPUC order, Met-Ed recognized a pre-tax charge of approximately $10.3 million in the third quarter of 2006, representing incremental costs deferred under the revised methodology in 2005. Met-Ed and Penelec continue to believe that the stranded cost accounting methodology modification is appropriate and on August 24, 2006 filed a petition with the PPUC pursuant to its order for authorization to reflect the stranded cost accounting methodology modification effective January 1, 1999. Hearings on this petition were held in February 2007 and briefing was completed on March 28, 2007. The ALJ's initial decision denied Met-Ed's and Penelec's request to modify their NUG stranded cost accounting methodology. The companies filed exceptions to the initial decision on May 23, 2007 and replies to those exceptions were filed on June 4, 2007. On November 8, 2007, the PPUC issued an order denying any changes in the accounting methodology for NUGs.

On May 2, 2007, Penn filed a plan with the PPUC for the procurement of default service supply from June 2008 through May 2011. The filing proposed multiple, competitive RFPs with staggered delivery periods for fixed-price, tranche-based, pay as bid default service supply to the residential and commercial classes. The proposal would phase out existing promotional rates and eliminates the declining block and the demand components on generation rates for residential and commercial customers. The industrial class default service would be provided through an hourly-priced service provided by Penn. Quarterly reconciliation of the differences between the costs of supply and revenues from customers was also proposed. On September 28, 2007, Penn filed a Joint Petition for Settlement resolving all but one issue in the case. Briefs were also filed on September 28, 2007 on the unresolved issue of incremental uncollectible accounts expense. The settlement was either supported, or not opposed, by all parties. On December 20, 2007, the PPUC approved the settlement except for the full requirements tranche approach for residential customers, which was remanded to the ALJ for hearings. Under the terms of the Settlement Agreement, the default service procurement for small commercial customers will be done with multiple RFPs, while the default service procurement for large commercial and industrial customers will utilize hourly pricing. Bids in the first RFP for small commercial load were received on February 20, 2008. In February 2008, parties filed direct and rebuttal testimony in the remand proceeding for the residential procurement approach. An evidentiary hearing was held on February 26, 2008, and this matter will be presented to the PPUC for its consideration by March 13, 2008.

On February 1, 2007, the Governor of Pennsylvania proposed an EIS. The EIS includes four pieces of proposed legislation that, according to the Governor, is designed to reduce energy costs, promote energy independence and stimulate the economy. Elements of the EIS include the installation of smart meters, funding for solar panels on residences and small businesses, conservation and demand reduction programs to meet energy growth, a requirement that electric distribution companies acquire power that results in the "lowest reasonable rate on a long-term basis," the utilization of micro-grids and a three year phase-in of rate increases. On July 17, 2007 the Governor signed into law two pieces of energy legislation. The first amended the Alternative Energy Portfolio Standards Act of 2004 to, among other things, increase the percentage of solar energy that must be supplied at the conclusion of an electric distribution company's transition period. The second law allows electric distribution companies, at their sole discretion, to enter into long term contracts with large customers and to build or acquire interests in electric generation facilities specifically to supply long-term contracts with such customers. A special legislative session on energy was convened in mid-September 2007 to consider other aspects of the EIS. On December 12, 2007, the Pennsylvania Senate passed the Alternative Energy Investment Act which, as amended, provides over $650 million over ten years to implement the Governor's proposal. The bill was then referred to the House Environmental Resources and Energy Committee where it awaits consideration. On February 12, 2008, the Pennsylvania House passed House Bill 2200 which provides for energy efficiency and demand management programs and targets as well as the installation of smart meters within ten years. Other legislation has been introduced to address generation procurement, expiration of rate caps, conservation and renewable energy. The final form of this pending legislation is uncertain. Consequently, FirstEnergy is unable to predict what impact, if any, such legislation may have on its operations.

(D) NEW JERSEY

JCP&L is permitted to defer for future collection from customers the amounts by which its costs of supplying BGS to non-shopping customers and costs incurred under NUG agreements exceed amounts collected through BGS and NUGC rates and market sales of NUG energy and capacity. As of December 31, 2007, the accumulated deferred cost balance totaled approximately $322 million.

In accordance with an April 28, 2004 NJBPU order, JCP&L filed testimony on June 7, 2004 supporting 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, JCP&L 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, JCP&L filed a response to those 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 the PUHCA pursuant to the EPACT. The NJBPU approved regulations effective October 2, 2006 that 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 JCP&L. 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. The NJBPU Staff circulated revised drafts of the proposal to interested stakeholders in November 2006 and again in February 2007. On February 1, 2008, the NJBPU accepted proposed rules for publication in the New Jersey Register on March 17, 2008. An April 23, 2008 public hearing on these proposed rules is expected to be scheduled with comments from interested parties expected to be due on May 17, 2008.

New Jersey statutes require that the state periodically undertake a planning process, known as the 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 New Jersey'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;
- Maintain unit prices for electricity to 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 obtain input from a broad range of interested stakeholders including utilities, environmental groups, customer groups, and major customers. EMP working groups addressing: (1) energy efficiency and demand response; (2) renewables; (3) reliability; and (4) pricing issues, have completed their assigned tasks of data gathering and analysis and have provided reports to the EMP Committee. Public stakeholder meetings were held in the fall of 2006 and in early 2007, and further public meetings are expected in 2008. At this time, FirstEnergy cannot predict the outcome of this process nor determine the impact, if any, such legislation may have on its operations or those of JCP&L.

On February 13, 2007, the NJBPU Staff informally issued a draft proposal relating to changes to the regulations addressing electric distribution service reliability and quality standards. Meetings between the NJBPU Staff and interested stakeholders to discuss the proposal were held and additional, revised informal proposals were subsequently circulated by the Staff. On September 4, 2007, proposed regulations were published in the New Jersey Register, which proposal will be subsequently considered by the NJBPU following comments that were submitted in September and October 2007. At this time, FirstEnergy cannot predict the outcome of this process nor determine the impact, if any, such regulations may have on its operations or those of JCP&L.

(E) FERC MATTERS

Transmission Service between MISO and PJM

On November 18, 2004, the FERC issued an order eliminating the through and out rate for transmission service between the MISO and PJM regions. FERC's intent was to eliminate so-called "pancaking" of transmission charges 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 rate mechanism to recover lost transmission revenues created by elimination of this charge (referred to as the Seams Elimination Cost Adjustment or "SECA") during a 16-month transition period. The FERC issued orders in 2005 setting the SECA for hearing. The presiding judge issued an initial decision on August 10, 2006, rejecting the compliance filings made by MISO, PJM, and the transmission owners, 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 the first quarter of 2008.

PJM Transmission Rate Design

On January 31, 2005, certain PJM transmission owners made filings with the FERC pursuant to a settlement agreement previously approved by the FERC. JCP&L, 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. Hearings were held and numerous parties appeared and litigated various issues concerning PJM rate design; notably AEP, which proposed to create a "postage stamp", or average rate for all high voltage transmission facilities across PJM and a zonal transmission rate for facilities below 345 kV. This proposal would have the effect of shifting recovery of the costs of high voltage transmission lines to other transmission zones, including those where JCP&L, Met-Ed, and Penelec serve load. The ALJ issued an initial decision directing that the cost of all PJM transmission facilities, regardless of voltage, should be recovered through a postage stamp rate. The ALJ recommended an April 1, 2006 effective date for this change in rate design. Numerous parties, including FirstEnergy, submitted briefs opposing the ALJ's decision and recommendations. On April 19, 2007, the FERC issued an order rejecting the ALJ's findings and recommendations in nearly every respect. The FERC found that the PJM transmission owners' existing "license plate" or zonal rate design was just and reasonable and ordered that the current license plate rates for existing transmission facilities be retained. On the issue of rates for new transmission facilities, the FERC directed that costs for new transmission facilities that are rated at 500 kV or higher are to be collected from all transmission zones throughout the PJM footprint by means of a postage-stamp rate. Costs for new transmission facilities that are rated at less than 500 kV, however, are to be allocated on a "beneficiary pays" basis. FERC found that PJM's current beneficiary-pays cost allocation methodology is not sufficiently detailed and, in a related order that also was issued on April 19, 2007, directed that hearings be held for the purpose of establishing a just and reasonable cost allocation methodology for inclusion in PJM's tariff.

On May 18, 2007, certain parties filed for rehearing of the FERC's April 19, 2007 order. On January 31, 2008, the requests for rehearing were denied. The FERC's orders on PJM rate design will prevent the allocation of a portion of the revenue requirement of existing transmission facilities of other utilities to JCP&L, Met-Ed and Penelec. In addition, the FERC's decision to allocate the cost of new 500 kV and above transmission facilities on a PJM-wide basis will reduce future transmission revenue recovery from the JCP&L, Met-Ed and Penelec zones. A partial settlement agreement addressing the "beneficiary pays" methodology for below 500 kV facilities, but excluding the issue of allocating new facilities costs to merchant transmission entities, was filed on September 14, 2007. The agreement was supported by the FERC's Trial Staff, and was certified by the Presiding Judge. The FERC's action on the settlement agreement is pending. The remaining merchant transmission cost allocation issues will proceed to hearing in May 2008. On February 13, 2008, AEP appealed the FERC's orders to the federal Court of Appeals for the D.C. Circuit. The Illinois Commerce Commission has also appealed these orders.

Post Transition Period Rate Design

FERC had directed MISO, PJM, and the respective transmission owners to make filings on or before August 1, 2007 to reevaluate transmission rate design within the MISO, and between MISO and PJM. On August 1, 2007, filings were made by MISO, PJM, and the vast majority of transmission owners, including FirstEnergy affiliates, which proposed to retain the existing transmission rate design. These filings were approved by the FERC on January 31, 2008. As a result of FERC's approval, the rates charged to FirstEnergy's load-serving affiliates for transmission service over existing transmission facilities in MISO and PJM are unchanged. In a related filing, MISO and MISO transmission owners requested that the current MISO pricing for new transmission facilities that spreads 20% of the cost of new 345 kV and higher transmission facilities across the entire MISO footprint (known as the RECB methodology) be retained.

Certain stand-alone transmission companies in MISO made a filing under Section 205 of the Federal Power Act requesting that 100% of the cost of new qualifying 345 kV and higher transmission facilities be spread throughout the entire MISO footprint. Further, Indianapolis Power and Light Company separately moved the FERC to reopen the record to address the cost allocation under the RECB methodology. FERC rejected these requests in an order issued January 31, 2008 again maintaining the status quo with respect to allocation of the cost of new transmission facilities in the MISO.

On September 17, 2007, AEP filed a complaint under Sections 206 and 306 of the Federal Power Act seeking to have the entire transmission rate design and cost allocation methods used by MISO and PJM declared unjust, unreasonable, and unduly discriminatory, and to have FERC fix a uniform regional transmission rate design and cost allocation method for the entire MISO and PJM "Super Region" that recovers the average cost of new and existing transmission facilities operated at voltages of 345 kV and above from all transmission customers. Lower voltage facilities would continue to be recovered in the local utility transmission rate zone through a license plate rate. AEP requested a refund effective October 1, 2007, or alternatively, February 1, 2008. On January 31, 2008, FERC issued an order denying the complaint.

Distribution of MISO Network Service Revenues

Effective February 1, 2008, the MISO Transmission Owners Agreement provides for a change in the method of distributing transmission revenues among the transmission owners. MISO and a majority of the MISO transmission owners filed on December 3, 2007 to change the MISO tariff to clarify, for purposes of distributing network transmission revenue to the transmission owners, that all network transmission service revenues, whether collected by MISO or directly by the transmission owner, are included in the revenue distribution calculation. This clarification was necessary because some network transmission service revenues are collected and retained by transmission owners in states where retail choice does not exist, and their "unbundled" retail load is currently exempt from MISO network service charges. The tariff changes filed with FERC ensure that revenues collected by transmission owners from bundled load are taken into account in the revenue distribution calculation, and that transmission owners with bundled load do not collect more than their revenue requirements. Absent the changes, transmission owners, and ultimately their customers, with unbundled load or in retail choice states, such as ATSI, would subsidize transmission owners with bundled load, who would collect their revenue requirement from bundled load, plus share in revenues collected by MISO from unbundled customers. This would result in a large revenue shortfall for ATSI, which would eventually be passed on to customers in the form of higher transmission rates as calculated pursuant to ATSI's Attachment O formula under the MISO tariff.

Numerous parties filed in support of the tariff changes, including the public service commissions of Michigan, Ohio and Wisconsin. Ameren filed a protest on December 26, 2007, arguing that the December 3 filing violates the MISO Transmission Owners' Agreement as well as an agreement among Ameren (Union Electric), MISO, and the Missouri Public Service Commission, which provides that Union Electric's bundled load cannot be charged by MISO for network service. On January 31, 2008, FERC issued an order conditionally accepting the tariff amendment subject to a minor compliance filing. This order ensures that ATSI will continue to receive transmission revenues from MISO equivalent to its transmission revenue requirement.

MISO Ancillary Services Market and Balancing Area Consolidation

MISO made a filing on September 14, 2007 to establish Ancillary Services markets for regulation, spinning and supplemental reserves, to consolidate the existing 24 balancing areas within the MISO footprint, and to establish MISO as the NERC registered balancing authority for the region. This filing would permit load serving entities to purchase their operating reserve requirements in a competitive market. An effective date of June 1, 2008 was requested in the filing.

MISO's previous filing to establish an Ancillary Services market was rejected without prejudice by FERC on June 22, 2007, subject to MISO providing an analysis of market power within its footprint and a plan to ensure reliability during the consolidation of balancing areas. MISO made a September 14 filing addressing the FERC's directives. FirstEnergy supports the proposal to establish markets for Ancillary Services and consolidate existing balancing areas, but filed objections on specific aspects of the MISO proposal. Interventions and protests to MISO's filing were made with FERC on October 15, 2007. FERC conducted a technical conference on certain aspects of the MISO proposal on December 6, 2007, and additional comments were filed by FirstEnergy and other parties on December 19, 2007. FERC action is anticipated in the first quarter of 2008.

Duquesne's Request to Withdraw from PJM

On November 8, 2007, Duquesne Light Company (Duquesne) filed a request with the FERC to exit PJM and to join the MISO. In its filing, Duquesne asked FERC to be relieved of certain capacity payment obligations to PJM for capacity auctions conducted prior to its departure from PJM, but covering service for planning periods through May 31, 2010. Duquesne asserted that its primary reason for exiting PJM is to avoid paying future obligations created by PJM's forward capacity market. FirstEnergy believes that Duquesne's filing did not identify or address numerous legal, financial or operational issues that are implicated or affected directly by Duquesne's proposal. Consequently, on December 4, 2007 and January 3, 2008, FirstEnergy submitted responsive filings that, while conceding Duquesne's rights to exit PJM, contested various aspects of Duquesne's proposal. FirstEnergy particularly focused on Duquesne's proposal that it be allowed to exit PJM without payment of its share of existing capacity market commitments. FirstEnergy also objected to Duquesne's failure to address the firm transmission service requirements that would be necessary for FirstEnergy to continue to use the Beaver Valley Plant to meet existing commitments in the PJM capacity markets and to serve native load. Additionally, FirstEnergy protested Duquesne's failure to identify or address a number of legal, financial or operational issues and uncertainties that may or will result for both PJM and MISO market participants. Other market participants also submitted filings contesting Duquesne's plans.

On January 17, 2008, the FERC conditionally approved Duquesne's request to exit PJM. Among other conditions, FERC obligated Duquesne to pay the PJM capacity obligations that had accrued prior to January 17, 2008. Duquesne was given until February 1, 2008 to provide FERC written notice of its intent to withdraw and Duquesne filed the notice on February 1st. The FERC's order took notice of the numerous transmission and other issues raised by FirstEnergy and other parties to the proceeding, but did not provide any responsive rulings or other guidance. Rather, FERC ordered Duquesne to make a compliance filing in forty-five days from the FERC order (or by March 3, 2008) detailing how Duquesne will satisfy its obligations under the PJM Transmission Owners' Agreement. The FERC likewise directed the MISO to submit a compliance filing in forty-five days (or by March 3, 2008) detailing the MISO's plans to integrate Duquesne into the MISO. Finally, the FERC directed MISO and PJM to work together to resolve the substantive and procedural issues implicated by Duquesne's transition into the MISO. On February 19, 2008, we asked for clarification or rehearing of certain of the matters addressed in FERC's January 17, 2008 Order.

MISO Resource Adequacy Proposal

MISO made a filing on December 28, 2007 that would create an enforceable planning reserve requirement in the MISO tariff for load serving entities such as the Ohio Companies, Penn, and FES. This requirement is proposed to become effective for the planning year beginning June 1, 2009. The filing would permit MISO to establish the reserve margin requirement for load serving entities based upon a one day loss of load in ten years standard, unless the state utility regulatory agency establishes a different planning reserve for load serving entities in its state. FirstEnergy generally supports the proposal as it promotes a mechanism that will result in long-term commitments from both load-serving entities and resources, including both generation and demand side resources that are necessary for reliable resource adequacy and planning in the MISO footprint. FirstEnergy does not expect this filing to impose additional supply costs since its load serving entities in MISO are already bound by similar planning reserve requirements established by *ReliabilityFirst* Corporation. Comments on the filing were filed on January 28, 2008. An effective date of June 1, 2009 was requested in the filing, but MISO has requested FERC approval by the end of the first quarter of 2008.

Organized Wholesale Power Markets

On February 21, 2008, the FERC issued a NOPR through which it proposes to adopt new rules that it states will "improve operations in organized electric markets, boost competition and bring additional benefits to consumers." The proposed rule addresses demand response and market pricing during reserve shortages, long-term power contracting, market-monitoring policies, and responsiveness of RTOs and ISOs to stakeholders and customers. FirstEnergy has not yet had an opportunity to evaluate the impact of the proposed rule on its operations.

11. CAPITALIZATION

(A) COMMON STOCK

Retained Earnings and Dividends

As of December 31, 2007, FirstEnergy's unrestricted retained earnings were $3.5 billion. In addition to paying dividends from retained earnings, each of FirstEnergy's electric utility subsidiaries has authorization from the FERC to pay cash dividends to FirstEnergy from paid-in capital accounts, as long as its equity to total capitalization ratio (without consideration of retained earnings) remains above 35%. The articles of incorporation, indentures and various other agreements relating to the long-term debt and preferred stock of certain FirstEnergy subsidiaries contain provisions that could further restrict the payment of dividends on their common stock. With the exception of Met-Ed, which is currently in an accumulated deficit position, none of these provisions materially restricted FirstEnergy's subsidiaries' ability to pay cash dividends to FirstEnergy as of December 31, 2007.

On December 18, 2007, the Board of Directors increased the indicated annual common stock dividend to $2.20 per share, payable quarterly at a rate of $0.55 per share beginning in the first quarter of 2008. Dividends declared in 2007 were $2.05, which included three quarterly dividends of $0.50 per share paid in the second, third and fourth quarters of 2007 and a quarterly dividend of $0.55 per share payable in the first quarter of 2008. Dividends declared in 2006 were $1.85, which included three quarterly dividends of $0.45 per share paid in the second, third and fourth quarters of 2006 and a quarterly dividend of $0.50 per share paid in the first quarter of 2007. The amount and timing of all dividend declarations are subject to the discretion of the Board and its consideration of business conditions, results of operations, financial condition and other factors.

(B) PREFERRED AND PREFERENCE STOCK

FirstEnergy's and the Companies' preferred stock and preference stock authorizations are as follows:

	Preferred Stock		Preference Stock	
	Shares Authorized	Par Value	Shares Authorized	Par Value
FirstEnergy	5,000,000	$100		
OE	6,000,000	$100	8,000,000	no par
OE	8,000,000	$25		
Penn	1,200,000	$100		
CEI	4,000,000	no par	3,000,000	no par
TE	3,000,000	$100	5,000,000	$25
TE	12,000,000	$25		
JCP&L	15,600,000	no par		
Met-Ed	10,000,000	no par		
Penelec	11,435,000	no par		

No preferred shares or preference shares are currently outstanding. The following table details the change in preferred shares outstanding for the three years ended December 31, 2007.

	Not Subject to Mandatory Redemption		Subject to Mandatory Redemption	
	Number of Shares	Par or Stated Value	Number of Shares	Par or Stated Value
	(Dollars in millions)			
Balance, January 1, 2005	6,209,699	$ 335	167,500	$ 17
Redemptions-				
7.750% Series	(250,000)	(25)		
$7.40 Series A	(500,000)	(50)		
Adjustable Series L	(474,000)	(46)		
Adjustable Series A	(1,200,000)	(30)		
7.625% Series			(127,500)	(13)
$7.35 Series C			(40,000)	(4)
Balance, December 31, 2005	3,785,699	184	-	-
Redemptions-				
3.90% Series	(152,510)	(15)		
4.40% Series	(176,280)	(18)		
4.44% Series	(136,560)	(14)		
4.56% Series	(144,300)	(14)		
4.24% Series	(40,000)	(4)		
4.25% Series	(41,049)	(4)		
4.64% Series	(60,000)	(6)		
$4.25 Series	(160,000)	(16)		
$4.56 Series	(50,000)	(5)		
$4.25 Series	(100,000)	(10)		
$2.365 Series	(1,400,000)	(35)		
Adjustable Series B	(1,200,000)	(30)		
4.00% Series	(125,000)	(13)		
Balance, December 31, 2006	-	-	-	-
Balance, December 31, 2007	-	$ -	-	$ -

(C) LONG-TERM DEBT AND OTHER LONG-TERM OBLIGATIONS

Securitized Transition Bonds

The consolidated financial statements of FirstEnergy and 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 and JCP&L's Consolidated Balance Sheets. As of December 31, 2007, $397 million of the transition bonds were 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

Each of the Companies, except for JCP&L, has a first mortgage indenture under which it issues FMB secured by a direct first mortgage lien on substantially all of its property and franchises, other than specifically excepted property. JCP&L satisfied the provision of its senior note indenture for the release of all FMBs held as collateral for senior notes in May 2007, subsequently repaid its other remaining FMBs and, effective September 14, 2007, discharged and released its mortgage indenture.

FirstEnergy and its subsidiaries have various debt covenants under their respective financing arrangements. The most restrictive of the debt covenants relate to the nonpayment of interest and/or principal on debt and the maintenance of certain financial ratios. There also exist cross-default provisions among financing arrangements of FirstEnergy, FES and the Companies.

Based on the amount of FMB authenticated by the respective mortgage bond trustees through December 31, 2007, the Companies' annual sinking fund requirement for all FMB issued under the various mortgage indentures amounted to $50 million. Penn expects to deposit funds with its mortgage bond trustee in 2008 that will then be withdrawn upon the surrender for cancellation of a like principal amount of FMB, specifically authenticated for such purposes against unfunded property additions or against previously retired FMB. This method can result in minor increases in the amount of the annual sinking fund requirement. Met-Ed and Penelec could fulfill their sinking fund obligations by providing bondable property additions, previously retired FMB or cash to the respective mortgage bond trustees.

Sinking fund requirements for FMB and maturing long-term debt (excluding capital leases) for the next five years are:

	(In millions)
2008	$ 2,013
2009	287
2010	214
2011	1,540
2012	43

Included in the table above are amounts for certain variable interest rate pollution control revenue bonds that currently bear interest in an interest rate mode that permits individual debt holders to put the respective debt back to the issuer for purchase prior to maturity. These amounts are $1.7 billion and $15 million in 2008 and 2010, respectively, representing the next time the debt holders may exercise this right. The applicable pollution control revenue bond indentures provide that bonds so tendered for purchase will be remarketed by a designated remarketing agent.

Obligations to repay certain pollution control revenue bonds are secured by several series of FMB. Certain pollution control revenue bonds are entitled to the benefit of irrevocable bank LOCs of $1.6 billion as of December 31, 2007, or noncancelable municipal bond insurance of $593 million as of December 31, 2007, to pay principal of, or interest on, the applicable pollution control revenue bonds. To the extent that drawings are made under the LOCs or the insurance, FGCO, NGC and the Companies are entitled to a credit against their obligation to repay those bonds. FGCO, NGC and the Companies pay annual fees of 0.15% to 1.70% of the amounts of the LOCs to the issuing banks and 0.15% to 0.16% of the amounts of the insurance policies to the insurers and are obligated to reimburse the banks or insurers, as the case may be, for any drawings thereunder. Certain of the issuing banks and insurers hold FMB as security for such reimbursement obligations.

CEI and TE have unsecured LOCs of approximately $194 million in connection with the sale and leaseback of Beaver Valley Unit 2 for which they are jointly and severally liable. OE has LOCs of $291 million and $134 million in connection with the sale and leaseback of Beaver Valley Unit 2 and Perry Unit 1, respectively. OE entered into a Credit Agreement pursuant to which a standby LOC was issued in support of approximately $236 million of the Beaver Valley Unit 2 LOCs and the issuer of the standby LOC obtained the right to pledge or assign participations in OE's reimbursement obligations under the credit agreement to a trust. The trust then issued and sold trust certificates to institutional investors that were designed to be the credit equivalent of an investment directly in OE.

12. ASSET RETIREMENT OBLIGATIONS

FirstEnergy has recognized applicable legal obligations under SFAS 143 for nuclear power plant decommissioning, reclamation of a sludge disposal pond and closure of two coal ash disposal sites. In addition, FirstEnergy has recognized conditional retirement obligations (primarily for asbestos remediation) in accordance with FIN 47, which was implemented on December 31, 2005.

The ARO liability of $1.3 billion as of December 31, 2007 primarily relates to the nuclear decommissioning of the Beaver Valley, Davis-Besse, Perry and TMI-2 nuclear generating facilities. FirstEnergy uses an expected cash flow approach to measure the fair value of the nuclear decommissioning ARO.

In 2006, FirstEnergy revised the ARO associated with Perry as a result of revisions to the 2005 decommissioning study. The present value of revisions in the estimated cash flows associated with projected decommissioning costs increased the ARO and corresponding plant asset for Perry by $4 million. The ARO for FirstEnergy's sludge disposal pond located near the Bruce Mansfield Plant was revised in 2006 due to an updated cost study. The present value of revisions in the estimated cash flows associated with projected remediation costs associated with the site decreased the ARO and corresponding plant asset by $6 million. In May 2006, CEI sold its interest in the Ashtabula C plant. As part of the transaction, CEI settled the $6 million ARO that had been established with the adoption of FIN 47.

FirstEnergy maintains nuclear decommissioning trust funds that are legally restricted for purposes of settling the nuclear decommissioning ARO. As of December 31, 2007, the fair value of the decommissioning trust assets was approximately $2.1 billion.

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.

FirstEnergy identified applicable legal obligations as defined under the new standard at its active and retired generating units, substation control rooms, service center buildings, line shops and office buildings, identifying asbestos remediation as the primary conditional ARO. As a result of adopting FIN 47 in December 2005, FirstEnergy recorded a conditional ARO liability of $57 million (including accumulated accretion for the period from the date the liability was incurred to the date of adoption), an asset retirement cost of $16 million (recorded as part of the carrying amount of the related long-lived asset) and accumulated depreciation of $12 million. FirstEnergy charged regulatory liabilities for $5 million upon adoption of FIN 47 for the transition amounts related to establishing the ARO for asbestos removal from substation control rooms and service center buildings for OE, Penn, CEI, TE and JCP&L. The remaining cumulative effect adjustment for unrecognized depreciation and accretion of $48 million was charged to income ($30 million, net of tax), -- $0.09 per share of common stock (basic and diluted) for the year ended December 31, 2005.

The following table describes the changes to the ARO balances during 2007 and 2006.

ARO Reconciliation	2007	2006
	(In millions)	
Balance at beginning of year	$ 1,190	$ 1,126
Liabilities settled	(2)	(6)
Accretion	79	72
Revisions in estimated cash flows	-	(2)
Balance at end of year	$ 1,267	$ 1,190

13. SHORT-TERM BORROWINGS AND BANK LINES OF CREDIT

FirstEnergy had approximately $903 million of short-term indebtedness as of December 31, 2007, comprised of $800 million in borrowings under a $2.75 billion revolving line of credit and $103 million of other bank borrowings. Total short-term bank lines of committed credit to FirstEnergy and the Companies as of December 31, 2007 were approximately $3.4 billion.

FirstEnergy, along with certain of its subsidiaries, are parties to a $2.75 billion five-year revolving credit facility. FirstEnergy may request an increase in the total commitments available under this facility up to a maximum of $3.25 billion. Commitments under the facility are available until August 24, 2012, unless the lenders agree, at the request of the borrowers, to an unlimited number of 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 sub-limit, as well as applicable regulatory and other limitations. The annual facility fee is 0.125%

The Companies, with the exception of TE and JCP&L, each have a wholly owned subsidiary whose borrowings are secured by customer accounts receivable purchased from its respective parent company. The CEI subsidiary's borrowings are also secured by customer accounts receivable purchased from TE. Each subsidiary company has its own receivables financing arrangement and, as a separate legal entity with separate creditors, would have to satisfy its obligations to creditors before any of its remaining assets could be available to its parent company. The receivables financing borrowing capacity by company are shown in the following table. There were no outstanding borrowings as of December 31, 2007.

Subsidiary Company	Parent Company	Capacity	Annual Facility Fee
		(In millions)	
OES Capital, Incorporated	OE	$ 170	0.15%
Centerior Funding Corp.	CEI	200	0.15
Penn Power Funding LLC	Penn	25	0.13
Met-Ed Funding LLC	Met-Ed	80	0.13
Penelec Funding LLC	Penelec	75	0.13
		$ 550	

The weighted average interest rates on short-term borrowings outstanding as of December 31, 2007 and 2006 were 5.42% and 5.71%, respectively. The annual facility fees on all current committed short-term bank lines of credit range from 0.125% to 0.15%.

14. 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. FirstEnergy's maximum potential assessment under the industry retrospective rating plan would be $402 million per incident but not more than $60 million in any one year for each incident.

FirstEnergy is also insured under policies for each nuclear plant. Under these policies, up to $2.8 billion is provided for property damage and decontamination costs. FirstEnergy has also obtained approximately $2.0 billion of insurance coverage for replacement power costs. Under these policies, FirstEnergy can be assessed a maximum of approximately $81 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.

FirstEnergy intends to maintain insurance against nuclear risks, as described above, as long as it is available. To the extent that replacement power, property damage, decontamination, repair and replacement costs and other such costs arising from a nuclear incident at any of FirstEnergy's plants 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 FirstEnergy's insurance policies, or to the extent such insurance becomes unavailable in the future, FirstEnergy would remain at risk for such costs.

(B) GUARANTEES AND OTHER ASSURANCES

As part of normal business activities, FirstEnergy enters into various agreements on behalf of its subsidiaries to provide financial or performance assurances to third parties. These agreements include contract guarantees, surety bonds and LOCs. As of December 31, 2007, outstanding guarantees and other assurances aggregated approximately $4.5 billion, consisting of parental guarantees - $1.0 billion, subsidiaries' guarantees - $2.7 billion, surety bonds - $0.1 billion and LOCs - $0.7 billion.

FirstEnergy guarantees energy and energy-related payments of its subsidiaries involved in energy commodity activities principally to facilitate normal physical transactions involving electricity, gas, emission allowances and coal. FirstEnergy also provides guarantees to various providers of credit support for subsidiary financings or refinancings of costs related to the acquisition of property, plant and equipment. These agreements legally obligate FirstEnergy to fulfill the obligations of those subsidiaries directly involved in energy and energy-related transactions or financing where the law might otherwise limit the counterparties' claims. If demands of a counterparty were to exceed the ability of a subsidiary to satisfy existing obligations, FirstEnergy's guarantee enables the counterparty's legal claim to be satisfied by other FirstEnergy assets. The likelihood is remote that such parental guarantees of $0.5 billion (included in the $1.0 billion discussed above) as of December 31, 2007 would increase amounts otherwise payable by FirstEnergy to meet its obligations incurred in connection with financings and ongoing energy and energy-related activities.

While these types of guarantees are normally parental commitments for the future payment of subsidiary obligations, subsequent to the occurrence of a credit rating-downgrade or "material adverse event" the immediate posting of cash collateral or provision of an LOC may be required of the subsidiary. As of December 31, 2007, FirstEnergy's maximum exposure under these collateral provisions was $402 million.

Most of FirstEnergy's surety bonds are backed by various indemnities common within the insurance industry. Surety bonds and related FirstEnergy guarantees of $73 million provide additional assurance to outside parties that contractual and statutory obligations will be met in a number of areas including construction jobs, environmental commitments and various retail transactions.

FirstEnergy has also guaranteed the obligations of the operators of the TEBSA project, up to a maximum of $6 million (subject to escalation) under the project's operations and maintenance agreement. In connection with the sale of TEBSA in January 2004, the purchaser indemnified FirstEnergy against any loss under this guarantee. FirstEnergy has also provided an LOC ($19 million as of December 31, 2007), which is renewable and declines yearly based upon the senior outstanding debt of TEBSA.

On July 13, 2007, FGCO completed the sale and leaseback for its 93.825% undivided interest in Bruce Mansfield Unit 1 (see Note 6). FES has unconditionally and irrevocably guaranteed all of FGCO's obligations under each of the leases. The related lessor notes and pass through certificates are not guaranteed by FES or FGCO, but the notes are secured by, among other things, each lessor trust's undivided interest in Unit 1, rights and interests under the applicable lease and rights and interests under other related agreements, including FES' lease guaranty.

(C) ENVIRONMENTAL MATTERS

Various federal, state and local authorities regulate FirstEnergy with regard to air and water quality and other environmental matters. The effects of compliance on FirstEnergy with regard to environmental matters could have a material adverse effect on FirstEnergy's earnings and competitive position to the extent that it competes with companies that are not subject to such regulations and, therefore, do not bear the risk of costs associated with compliance, or failure to comply, with such regulations. FirstEnergy estimates capital expenditures for environmental compliance of approximately $1.4 billion for the period 2008-2012.

FirstEnergy 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 FirstEnergy's determination of environmental liabilities and are accrued in the period that they become both probable and reasonably estimable.

Clean Air Act Compliance

FirstEnergy is required to meet federally-approved SO_2 emissions regulations. Violations of such regulations can result in the shutdown of the generating unit involved and/or civil or criminal penalties of up to $32,500 for each day the unit is in violation. The EPA has an interim enforcement policy for SO_2 regulations in Ohio that allows for compliance based on a 30-day averaging period. FirstEnergy believes it is currently in compliance with this policy, but cannot predict what action the EPA may take in the future with respect to the interim enforcement policy.

The EPA Region 5 issued a Finding of Violation and NOV to the Bay Shore Power Plant dated June 15, 2006, alleging violations to various sections of the Clean Air Act. FirstEnergy has disputed those alleged violations based on its Clean Air Act permit, the Ohio SIP and other information provided to the EPA at an August 2006 meeting with the EPA. The EPA has several enforcement options (administrative compliance order, administrative penalty order, and/or judicial, civil or criminal action) and has indicated that such option may depend on the time needed to achieve and demonstrate compliance with the rules alleged to have been violated. On June 5, 2007, the EPA requested another meeting to discuss "an appropriate compliance program" and a disagreement regarding the opacity limit applicable to the common stack for Bay Shore Units 2, 3 and 4.

FirstEnergy complies with SO_2 reduction requirements under the Clean Air Act Amendments of 1990 by burning lower-sulfur fuel, generating more electricity from lower-emitting plants, and/or using emission allowances. NO_X reductions required by the 1990 Amendments are being achieved through combustion controls and the generation of more electricity at lower-emitting plants. In September 1998, the EPA finalized regulations requiring additional NO_X reductions at FirstEnergy's facilities. The EPA's NO_X Transport Rule imposes uniform reductions of NO_X emissions (an approximate 85% reduction in utility plant NO_X emissions from projected 2007 emissions) across a region of nineteen states (including Michigan, New Jersey, Ohio and Pennsylvania) and the District of Columbia based on a conclusion that such NO_X emissions are contributing significantly to ozone levels in the eastern United States. FirstEnergy believes its facilities are also complying with the NO_X budgets established under SIPs through combustion controls and post-combustion controls, including Selective Catalytic Reduction and SNCR systems, and/or using emission allowances.

On May 22, 2007, FirstEnergy and FGCO received a notice letter, required 60 days prior to the filing of a citizen suit under the federal Clean Air Act, alleging violations of air pollution laws at the Bruce Mansfield Plant, including opacity limitations. Prior to the receipt of this notice, the Plant was subject to a Consent Order and Agreement with the Pennsylvania Department of Environmental Protection concerning opacity emissions under which efforts to achieve compliance with the applicable laws will continue. On October 16, 2007, PennFuture filed a complaint, joined by three of its members, in the United States District Court for the Western District of Pennsylvania. On January 11, 2008, FirstEnergy filed a motion to dismiss claims alleging a public nuisance. FGCO is not required to respond to other claims until the Court rules on this motion to dismiss.

On December 18, 2007, the state of New Jersey filed a Clean Air Act citizen suit alleging new source review violations at the Portland Generation Station against Reliant (the current owner and operator), Sithe Energy (the purchaser of the Portland Station from Met-Ed in 1999), GPU, Inc. and Met-Ed. Specifically, New Jersey alleges that "modifications" at Portland Units 1 and 2 occurred between 1980 and 1995 without preconstruction new source review or permitting required by the Clean Air Act's prevention of significant deterioration program, and seeks injunctive relief, penalties, attorney fees and mitigation of the harm caused by excess emissions. Although it remains liable for civil or criminal penalties and fines that may be assessed relating to events prior to the sale of the Portland Station in 1999, Met-Ed is indemnified by Sithe Energy against any other liability arising under the CAA whether it arises out of pre-1999 or post-1999 events.

National Ambient Air Quality Standards

In March 2005, the EPA finalized the CAIR covering a total of 28 states (including Michigan, New Jersey, Ohio and Pennsylvania) and the District of Columbia based on proposed findings that air emissions from 28 eastern states and the District of Columbia significantly contribute to non-attainment of the NAAQS for fine particles and/or the "8-hour" ozone NAAQS in other states. CAIR requires reductions of NO_X and SO_2 emissions in two phases (Phase I in 2009 for NO_X, 2010 for SO_2 and Phase II in 2015 for both NO_X and SO_2). FirstEnergy's Michigan, Ohio and Pennsylvania fossil generation facilities will be subject to caps on SO_2 and NO_X emissions, whereas its New Jersey fossil generation facility will be subject to only a cap on NO_X emissions. According to the EPA, SO_2 emissions will be reduced by 45% (from 2003 levels) by 2010 across the states covered by the rule, with reductions reaching 73% (from 2003 levels) by 2015, capping SO_2 emissions in affected states to just 2.5 million tons annually. NO_X emissions will be reduced by 53% (from 2003 levels) by 2009 across the states covered by the rule, with reductions reaching 61% (from 2003 levels) by 2015, achieving a regional NO_X cap of 1.3 million tons annually. CAIR has been challenged in the United States Court of Appeals for the District of Columbia. The future cost of compliance with these regulations may be substantial and may depend on the outcome of this litigation and how CAIR is ultimately implemented.

Mercury Emissions

In December 2000, the EPA announced it would proceed with the development of regulations regarding hazardous air pollutants from electric power plants, identifying mercury as the hazardous air pollutant of greatest concern. In March 2005, the EPA finalized the CAMR, which provides a cap-and-trade program to reduce mercury emissions from coal-fired power plants in two phases; initially, capping national mercury emissions at 38 tons by 2010 (as a "co-benefit" from implementation of SO_2 and NO_X emission caps under the EPA's CAIR program) and 15 tons per year by 2018. Several states and environmental groups appealed CAMR to the United States Court of Appeals for the District of Columbia, which on February 8, 2008, vacated CAMR ruling that the EPA failed to take the necessary steps to "de-list" coal-fired power plants from its hazardous air pollutant program and, therefore, could not promulgate a cap and trade program. The EPA must now seek judicial review of that ruling or take regulatory action to promulgate new mercury emission standards for coal-fired power plants. FGCO's future cost of compliance with mercury regulations may be substantial and will depend on the action taken by the EPA and on how they are ultimately implemented.

Pennsylvania has submitted a new mercury rule for EPA approval that does not provide a cap-and-trade approach as in the CAMR, but rather follows a command-and-control approach imposing emission limits on individual sources. It is anticipated that compliance with these regulations, if approved by the EPA and implemented, would not require the addition of mercury controls at the Bruce Mansfield Plant, FirstEnergy's only Pennsylvania coal-fired power plant, until 2015, if at all.

W. H. Sammis Plant

In 1999 and 2000, the EPA issued an NOV and the DOJ filed a civil complaint against OE and Penn based on operation and maintenance of the W.H. Sammis Plant (Sammis NSR Litigation) and filed similar complaints involving 44 other U.S. power plants. This case, along with seven other similar cases, are referred to as the New Source Review (NSR) cases.

On March 18, 2005, OE and Penn announced that they had reached a settlement with the EPA, the DOJ and three states (Connecticut, New Jersey and New York) that resolved all issues related to the Sammis NSR litigation. This settlement agreement, which is in the form of a consent decree, was approved by the court on July 11, 2005, and requires reductions of NO_X and SO_2 emissions at the Sammis, Burger, Eastlake and Mansfield coal-fired plants through the installation of pollution control devices and provides for stipulated penalties for failure to install and operate such pollution controls in accordance with that agreement. Consequently, if FirstEnergy fails to install such pollution control devices, for any reason, including, but not limited to, the failure of any third-party contractor to timely meet its delivery obligations for such devices, FirstEnergy could be exposed to penalties under the Sammis NSR Litigation consent decree. Capital expenditures necessary to complete requirements of the Sammis NSR Litigation consent decree are currently estimated to be $1.3 billion for 2008-2012 ($650 million of which is expected to be spent during 2008, with the largest portion of the remaining $650 million expected to be spent in 2009). This amount is included in the estimated capital expenditures for environmental compliance referenced above.

The Sammis NSR Litigation consent decree also requires FirstEnergy to spend up to $25 million toward environmentally beneficial projects, $14 million of which is satisfied by entering into 93 MW (or 23 MW if federal tax credits are not applicable) of wind energy purchased power agreements with a 20-year term. An initial 16 MW of the 93 MW consent decree obligation was satisfied during 2006.

On August 26, 2005, FGCO entered into an agreement with Bechtel Power Corporation, or Bechtel, under which Bechtel will engineer, procure and construct AQC systems for the reduction of SO_2 emissions. FGCO also entered into an agreement with Babcock & Wilcox Company, or B&W, on August 25, 2006 to supply flue gas desulfurization systems for the reduction of SO_2 emissions. SCR systems for the reduction of NO_X emissions are also being installed at the Sammis Plant under a 1999 Agreement with B&W.

On April 2, 2007, the United States Supreme Court ruled that changes in annual emissions (in tons/year) rather than changes in hourly emissions rate (in kilograms/hour) must be used to determine whether an emissions increase triggers NSR. Subsequently, on May 8, 2007, the EPA proposed to change the NSR regulations to utilize changes in the hourly emission rate (in kilograms/hour) to determine whether an emissions increase triggers NSR. The EPA has not yet issued a final regulation. FGCO's future cost of compliance with those regulations may be substantial and will depend on how they are ultimately implemented.

Climate Change

In December 1997, delegates to the United Nations' climate summit in Japan adopted an agreement, the Kyoto Protocol, to address global warming by reducing the amount of man-made GHG emitted by developed countries by 2012. The United States signed the Kyoto Protocol in 1998 but it failed to receive the two-thirds vote required for ratification by the United States Senate. However, the Bush administration has committed the United States to a voluntary climate change strategy to reduce domestic GHG intensity – the ratio of emissions to economic output – by 18% through 2012. In addition, the EPACT established a Committee on Climate Change Technology to coordinate federal climate change activities and promote the development and deployment of GHG reducing technologies.

There are a number of initiatives to reduce GHG emissions under consideration at the federal, state and international level. At the international level, efforts to reach a new global agreement to reduce GHG emissions post-2012 have begun with the Bali Roadmap, which outlines a two-year process designed to lead to an agreement in 2009. At the federal level, members of Congress have introduced several bills seeking to reduce emissions of GHG in the United States, and the Senate Environmental and Public Works Committees have passed one such bill. State activities, primarily the northeastern states participating in the Regional Greenhouse Gas Initiative and western states led by California, have coordinated efforts to develop regional strategies to control emissions of certain GHGs.

On April 2, 2007, the United States Supreme Court found that the EPA has the authority to regulate CO_2 emissions from automobiles as "air pollutants" under the Clean Air Act. Although this decision did not address CO_2 emissions from electric generating plants, the EPA has similar authority under the Clean Air Act to regulate "air pollutants" from those and other facilities.

FirstEnergy cannot currently estimate the financial impact of climate change policies, although potential legislative or regulatory programs restricting CO_2 emissions could require significant capital and other expenditures. The CO_2 emissions per KWH of electricity generated by FirstEnergy is lower than many regional competitors due to its diversified generation sources, which include low or non-CO_2 emitting gas-fired and nuclear generators.

Clean Water Act

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

On September 7, 2004, the EPA established new performance standards under Section 316(b) of the Clean Water Act for reducing impacts on fish and shellfish from cooling water intake structures at certain existing large electric generating plants. The regulations call for reductions in impingement mortality (when aquatic organisms are pinned against screens or other parts of a cooling water intake system) and entrainment (which occurs when aquatic life is drawn into a facility's cooling water system). On January 26, 2007, the United States Court of Appeals for the Second Circuit remanded portions of the rulemaking dealing with impingement mortality and entrainment back to the EPA for further rulemaking and eliminated the restoration option from the EPA's regulations. On July 9, 2007, the EPA suspended this rule, noting that until further rulemaking occurs, permitting authorities should continue the existing practice of applying their best professional judgment (BPJ) to minimize impacts on fish and shellfish from cooling water intake structures. FirstEnergy is evaluating various control options and their costs and effectiveness. Depending on the outcome of such studies, the EPA's further rulemaking and any action taken by the states exercising BPJ, the future cost of compliance with these standards may require material capital expenditures.

Regulation of Hazardous Waste

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

Under NRC regulations, FirstEnergy must ensure that adequate funds will be available to decommission its nuclear facilities. As of December 31, 2007, FirstEnergy had approximately $1.5 billion invested in external trusts to be used for the decommissioning and environmental remediation of Davis-Besse, Beaver Valley and Perry. As part of the application to the NRC to transfer the ownership of these nuclear facilities to NGC in 2005, FirstEnergy agreed to contribute another $80 million to these trusts by 2010. Consistent with NRC guidance, utilizing a "real" rate of return on these funds of approximately 2% over inflation, these trusts are expected to exceed the minimum decommissioning funding requirements set by the NRC. Conservatively, these estimates do not include any rate of return that the trusts may earn over the 20-year plant useful life extensions that FirstEnergy (and Exelon for TMI-1 as it relates to the timing of the decommissioning of TMI-2) seeks for these facilities.

The Companies have been named as PRPs at waste disposal sites, which may require cleanup under the Comprehensive Environmental Response, Compensation, and Liability Act of 1980. Allegations of disposal of hazardous substances at historical sites and the liability involved are often unsubstantiated and subject to dispute; however, federal law provides that all PRPs for a particular site may be 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, 2007, based on estimates of the total costs of cleanup, the Companies' proportionate responsibility for such costs and the financial ability of other unaffiliated entities to pay. In addition, JCP&L has accrued liabilities of approximately $56 million for environmental remediation of former manufactured gas plants in New Jersey; those costs are being recovered by JCP&L through a non-bypassable SBC. Total liabilities of approximately $93 million have been accrued through December 31, 2007.

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

In August 2002, the trial court granted partial summary judgment to JCP&L and dismissed the plaintiffs' claims for consumer fraud, common law fraud, negligent misrepresentation, and strict product liability. In November 2003, the trial court granted JCP&L's motion to decertify the class and denied plaintiffs' motion to permit into evidence their class-wide damage model indicating damages in excess of $50 million. These class decertification and damage rulings were appealed to the Appellate Division. The Appellate Division issued a decision in July 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, NJ, based on a common incident involving the failure of the bushings of two large transformers in the Red Bank substation resulting in planned and unplanned outages in the area during a 2-3 day period. In 2005, JCP&L 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. Plaintiffs appealed this ruling to the New Jersey Appellate Division which, in March 2007, reversed the decertification of the Red Bank class and remanded this matter back to the Trial Court to allow plaintiffs sufficient time to establish a damage model or individual proof of damages. JCP&L filed a petition for allowance of an appeal of the Appellate Division ruling to the New Jersey Supreme Court which was denied in May 2007. Proceedings are continuing in the Superior Court. FirstEnergy is defending this class action but is unable to predict the outcome of this matter. No liability has been accrued as of December 31, 2007.

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.

On February 5, 2008, the PUCO entered an order dismissing four separate complaint cases before it relating to the August 14, 2003 power outages. The dismissal was filed by the complainants in accordance with a resolution reached between the FirstEnergy companies and the complainants in those four cases. Two of those cases which were originally filed in Ohio State courts involved individual complainants and were subsequently dismissed for lack of subject matter jurisdiction. Further appeals were unsuccessful. The other two complaint cases were filed by various insurance carriers either in their own name as subrogees or in the name of their insured, seeking reimbursement from various FirstEnergy companies (and, in one case, from PJM, MISO and AEP, as well) for claims paid to insureds for damages allegedly arising as a result of the loss of power on August 14, 2003. (Also relating to the August 14, 2003 power outages, a fifth case, involving another insurance company was voluntarily dismissed by the claimant in April 2007; and a sixth case, involving the claim of a non-customer seeking reimbursement for losses incurred when its store was burglarized on August 14, 2003 was dismissed by the court.) The order dismissing the PUCO cases, noted above, concludes all pending litigation related to the August 14, 2003 outages and the resolution will not have a material adverse effect on the financial condition, results of operations or cash flows of either FirstEnergy or any of its subsidiaries.

Nuclear Plant Matters

On May 14, 2007, the Office of Enforcement of the NRC issued a Demand for Information (DFI) to FENOC, following FENOC's reply to an April 2, 2007 NRC request for information, about two reports prepared by expert witnesses for an insurance arbitration (the insurance claim was subsequently withdrawn by FirstEnergy in December 2007) related to Davis-Besse. The NRC indicated that this information was needed for the NRC "to determine whether an Order or other action should be taken pursuant to 10 CFR 2.202, to provide reasonable assurance that FENOC will continue to operate its licensed facilities in accordance with the terms of its licenses and the Commission's regulations." FENOC was directed to submit the information to the NRC within 30 days. On June 13, 2007, FENOC filed a response to the NRC's Demand for Information reaffirming that it accepts full responsibility for the mistakes and omissions leading up to the damage to the reactor vessel head and that it remains committed to operating Davis-Besse and FirstEnergy's other nuclear plants safely and responsibly. FENOC submitted a supplemental response clarifying certain aspects of the DFI response to the NRC on July 16, 2007. On August 15, 2007, the NRC issued a confirmatory order imposing these commitments. FENOC must inform the NRC's Office of Enforcement after it completes the key commitments embodied in the NRC's order. FENOC's compliance with these commitments is subject to future NRC review.

Other Legal Matters

There are various lawsuits, claims (including claims for asbestos exposure) and proceedings related to FirstEnergy's normal business operations pending against FirstEnergy and its subsidiaries. The other potentially material items not otherwise discussed above are described below.

On August 22, 2005, a class action complaint was filed against OE in Jefferson County, Ohio Common Pleas Court, seeking compensatory and punitive damages to be determined at trial based on claims of negligence and eight other tort counts alleging damages from W.H. Sammis Plant air emissions. The two named plaintiffs are also seeking injunctive relief to eliminate harmful emissions and repair property damage and the institution of a medical monitoring program for class members. On April 5, 2007, the Court rejected the plaintiffs' request to certify this case as a class action and, accordingly, did not appoint the plaintiffs as class representatives or their counsel as class counsel. On July 30, 2007, plaintiffs' counsel voluntarily withdrew their request for reconsideration of the April 5, 2007 Court order denying class certification and the Court heard oral argument on the plaintiffs' motion to amend their complaint which OE has opposed. On August 2, 2007, the Court denied the plaintiffs' motion to amend their complaint. The plaintiffs have appealed the Court's denial of the motion for certification as a class action and motion to amend their complaint.

JCP&L's bargaining unit employees filed a grievance challenging JCP&L'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 JCP&L appeal of the award filed on October 18, 2005. A final order identifying the individual damage amounts was issued on October 31, 2007. The award appeal process was initiated. The union filed a motion with the federal court to confirm the award and JCP&L filed its answer and counterclaim to vacate the award on December 31, 2007. The court is expected to issue a briefing schedule at its April 2008 scheduling conference. JCP&L 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.

15. FIRSTENERGY INTRA-SYSTEM GENERATION ASSET TRANSFERS

In 2005, the Ohio Companies and Penn transferred their respective undivided ownership interests in FirstEnergy's nuclear and non-nuclear generation assets to NGC and FGCO, respectively. All of the non-nuclear assets were transferred to FGCO under the purchase option terms of a Master Facility Lease between FGCO and the Ohio Companies and Penn, under which FGCO leased, operated and maintained the assets that it now owns. CEI and TE sold their interests in nuclear generation assets at net book value to NGC, while OE and Penn transferred their interests to NGC through an asset spin-off in the form of a dividend. On December 28, 2006, the NRC approved the transfer of ownership in NGC from FirstEnergy to FES. Effective December 31, 2006, NGC is a wholly owned subsidiary of FES and second tier subsidiary of FirstEnergy. FENOC continues to operate and maintain the nuclear generation assets.

Although the generating plant interests transferred in 2005 did not include leasehold interests of CEI, OE and TE in certain of the plants that are subject to sale and leaseback arrangements entered into in 1987 with non-affiliates, effective October 16, 2007, CEI and TE assigned their leasehold interests in the Bruce Mansfield Plant to FGCO. FGCO assumed all of CEI's and TE's obligations arising under those leases. FGCO subsequently transferred the Unit 1 portion of these leasehold interests, as well as FGCO's leasehold interests under its July 13, 2007 Bruce Mansfield Unit 1 sale and leaseback transaction, to a newly formed wholly-owned subsidiary on December 17, 2007. The subsidiary assumed all of the lessee obligations associated with the assigned interests. However, CEI and TE remain primarily liable on the 1987 leases and related agreements. FGCO remains primarily liable on the 2007 leases and related agreements, and FES remains primarily liable as a guarantor under the related 2007 guarantees, as to the lessors and other parties to the respective agreements.

These transactions above were undertaken pursuant to the Ohio Companies' and Penn's restructuring plans that were approved by the PUCO and the PPUC, respectively, under applicable Ohio and Pennsylvania electric utility restructuring legislation. Consistent with the restructuring plans, generation assets that had been owned by the Ohio Companies and Penn were required to be separated from the regulated delivery business of those companies through transfer or sale to a separate corporate entity. The transactions essentially completed the divestitures of owned assets contemplated by the restructuring plans by transferring the ownership interests to NGC and FGCO without impacting the operation of the plants. The transfers were intracompany transactions and, therefore, had no impact on our consolidated results.

16. SEGMENT INFORMATION

FirstEnergy has three reportable operating segments: energy delivery services, competitive energy services and Ohio transitional generation services. The "Other" segment primarily consists of telecommunications services and other non-core assets. The assets and revenues for the other business operations are below the quantifiable threshold for operating segments for separate disclosure as "reportable operating segments."

The energy delivery services segment designs, constructs, operates and maintains FirstEnergy's regulated transmission and distribution systems and is responsible for the regulated generation commodity operations of FirstEnergy's Pennsylvania and New Jersey electric utility subsidiaries. Its revenues are primarily derived from the delivery of electricity, cost recovery of regulatory assets and default service electric generation sales to non-shopping customers in its Pennsylvania and New Jersey franchise areas. Its results reflect the commodity costs of securing electric generation from FES under partial requirements purchased power agreements and non-affiliated power suppliers as well as the net PJM transmission expenses related to the delivery of that generation load.

The competitive energy services segment supplies electric power to its electric utility affiliates, provides competitive electric sales primarily in Ohio, Pennsylvania, Maryland and Michigan, owns or leases and operates FirstEnergy's generating facilities and purchases electricity to meet its sales obligations. The segment's net income is primarily derived from the affiliated company PSA sales and the non-affiliated electric generation sales revenues less the related costs of electricity generation, including purchased power and net transmission (including congestion) and ancillary costs charged by PJM and MISO to deliver electricity to the segment's customers. The segment's internal revenues represent the affiliated company PSA sales.

The Ohio transitional generation services segment represents the regulated generation commodity operations of FirstEnergy's Ohio electric utility subsidiaries. Its revenues are primarily derived from electric generation sales to non-shopping customers under the PLR obligations of the Ohio Companies. Its results reflect the purchase of electricity from the competitive energy services segment through full requirements PSA arrangements, the deferral and amortization of certain fuel costs authorized for recovery by the energy delivery services segment and the net MISO transmission revenues and expenses related to the delivery of generation load. This segment's total assets consist of accounts receivable for generation revenues from retail customers.

Segment Financial Information	Energy Delivery Services	Competitive Energy Services	Ohio Transitional Generation Services	Other	Reconciling Adjustments	Consolidated
			(In millions)			
2007						
External revenues	$ 8,726	$ 1,468	$ 2,596	$ 39	$ (27)	$ 12,802
Internal revenues	-	2,901	-	-	(2,901)	-
Total revenues	8,726	4,369	2,596	39	(2,928)	12,802
Depreciation and amortization	1,024	204	(125)	4	26	1,133
Investment income	240	16	1	1	(138)	120
Net interest charges	445	152	1	4	141	743
Income taxes	574	330	69	4	(94)	883
Net income	862	495	103	12	(163)	1,309
Total assets	23,352	7,669	231	303	513	32,068
Total goodwill	5,583	24	-	-	-	5,607
Property additions	814	740	-	21	58	1,633
2006						
External revenues	$ 7,623	$ 1,429	$ 2,390	$ 95	$ (36)	$ 11,501
Internal revenues	14	2,609	-	-	(2,623)	-
Total revenues	7,637	4,038	2,390	95	(2,659)	11,501
Depreciation and amortization	845	190	(105)	4	23	957
Investment income	328	35	-	1	(215)	149
Net interest charges	433	188	1	6	74	702
Income taxes	595	262	75	(21)	(116)	795
Income from continuing operations	893	393	112	44	(184)	1,258
Discontinued operations	-	-	-	(4)	-	(4)
Net income	893	393	112	40	(184)	1,254
Total assets	22,863	6,978	215	297	843	31,196
Total goodwill	5,873	24	-	1	-	5,898
Property additions	629	644	-	1	41	1,315
2005						
External revenues	$ 8,165	$ 1,550	$ 1,568	$ 115	$ (40)	$ 11,358
Internal revenues	33	2,425	-	-	(2,458)	-
Total revenues	8,198	3,975	1,568	115	(2,498)	11,358
Depreciation and amortization	1,341	187	(91)	2	25	1,464
Investment income	262	79	-	-	(124)	217
Net interest charges	375	191	1	6	83	656
Income taxes	672	132	(49)	12	(18)	749
Income (loss) from continuing operations	1,008	199	(73)	14	(269)	879
Discontinued operations	-	-	-	12	-	12
Cumulative effect of accounting change	(21)	(9)	-	-	-	(30)
Net income (loss)	987	190	(73)	26	(269)	861
Total assets	23,834	6,556	141	605	705	31,841
Total goodwill	5,932	24	-	54	-	6,010
Property additions	782	375	-	8	43	1,208

Reconciling adjustments to segment operating results from internal management reporting to consolidated external financial reporting primarily consist of interest expense related to holding company debt, corporate support services revenues and expenses and elimination of intersegment transactions.

*Products and Services**

Year	Electricity Sales	Energy Related Sales and Services
	(In millions)	
2007	$ 11,944	$ -
2006	10,671	48
2005	10,546	77

* See Note 8 for discussion of discontinued operations.

17. NEW ACCOUNTING STANDARDS AND INTERPRETATIONS

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 and its related FSPs are effective for fiscal years beginning after November 15, 2007, and interim periods within those years. Under FSP FAS 157-2, FirstEnergy has elected to defer the election of SFAS 157 for financial assets and financial liabilities measured at fair value on a non-recurring basis for one year. FirstEnergy has evaluated the impact of this Statement and its FSPs, FSP FAS 157-2 and FSP FAS 157-1, which excludes SFAS 13, *Accounting for Leases,* and its related pronouncements from the scope of SFAS 157, and does not expect there to be a material effect on its financial statements. The majority of our fair value measurements will be disclosed as level 1 or level 2 in the fair value hierarchy.

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

In February 2007, the FASB issued SFAS 159, which provides companies with an option to report selected financial assets and financial liabilities at fair value. This Statement attempts to provide additional information that will help investors and other users of financial statements to more easily understand the effect of a 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 and SFAS 107. This Statement is effective for fiscal years beginning after November 15, 2007, and interim periods within those years. FirstEnergy has analyzed its financial assets and financial liabilities within the scope of this Statement and no fair value elections were made as of January 1, 2008.

SFAS 141(R) – "Business Combinations"

In December 2007, the FASB issued SFAS 141(R), which requires the acquiring entity in a business combination to recognize all the assets acquired and liabilities assumed in the transaction; establishes the acquisition-date fair value as the measurement objective for all assets acquired and liabilities assumed; and requires the acquirer to disclose to investors and other users all of the information they need to evaluate and understand the nature and financial effect of the business combination. SFAS 141(R) attempts to reduce the complexity of existing GAAP related to business combinations. The Standard includes both core principles and pertinent application guidance, eliminating the need for numerous EITF issues and other interpretative guidance. SFAS 141(R) will affect business combinations FirstEnergy enters that close after January 1, 2009. In addition, the Standard also affects the accounting for changes in tax valuation allowances made after January 1, 2009, that were established as part of a business combination prior to the implementation of this standard. FirstEnergy is currently evaluating the impact of adopting this Standard on its financial statements.

SFAS 160 - "Noncontrolling Interests in Consolidated Financial Statements – an Amendment of ARB No. 51"

In December 2007, the FASB issued SFAS 160 that establishes accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. It clarifies that a noncontrolling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. This Statement is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. Early adoption is prohibited. The Statement is not expected to have a material impact on FirstEnergy's financial statements.

FSP FIN 39-1 – "Amendment of FASB Interpretation No. 39"

In April 2007, the FASB issued Staff Position (FSP) FIN 39-1, which permits an entity to offset fair value amounts recognized for the right to reclaim cash collateral (a receivable) or the obligation to return cash collateral (a payable) against fair value amounts recognized for derivative instruments that have been offset under the same master netting arrangement as the derivative instruments. This FSP is effective for fiscal years beginning after November 15, 2007, with early application permitted. The effects of applying the guidance in this FSP should be recognized as a retroactive change in accounting principle for all financial statements presented. FSP FIN 39-1 is not expected to have a material effect on FirstEnergy's financial statements.

EITF 06-11 – "Accounting for Income Tax Benefits of Dividends or Share-based Payment Awards"

In June 2007, the FASB released EITF 06-11, which provides guidance on the appropriate accounting for income tax benefits related to dividends earned on nonvested share units that are charged to retained earnings under SFAS 123(R). The consensus requires that an entity recognize the realized tax benefit associated with the dividends on nonvested shares as an increase to APIC. This amount should be included in the APIC pool, which is to be used when an entity's estimate of forfeitures increases or actual forfeitures exceed its estimates, at which time the tax benefits in the APIC pool would be reclassified to the income statement. The consensus is effective for income tax benefits of dividends declared during fiscal years beginning after December 15, 2007. EITF 06-11 is not expected to have a material effect on FirstEnergy's financial statements.

18. SUMMARY OF QUARTERLY FINANCIAL DATA (UNAUDITED)

The following summarizes certain consolidated operating results by quarter for 2007 and 2006.

Three Months Ended	March 31, 2007	June 30, 2007	September 30, 2007	December 31, 2007
	(In millions, except per share amounts)			
Revenues	$ 2,973	$ 3,109	$ 3,641	$ 3,079
Expenses	2,336	2,381	2,791	2,479
Operating Income	637	728	850	600
Other Expense	147	168	164	144
Income From Continuing Operations Before Income Taxes	490	560	686	456
Income Taxes	200	222	273	188
Income From Continuing Operations	290	338	413	268
Net Income	$ 290	$ 338	$ 413	$ 268
Earnings Per Share of Common Stock:				
Basic	$ 0.92	$ 1.11	$ 1.36	$ 0.88
Diluted	$ 0.92	$ 1.10	$ 1.34	$ 0.87

Three Months Ended	March 31, 2006	June 30, 2006	September 30, 2006	December 31, 2006
	(In millions, except per share amounts)			
Revenues	$ 2,705	$ 2,751	$ 3,364	$ 2,680
Expenses	2,234	2,081	2,505	2,076
Operating Income	471	670	859	604
Other Expense	117	142	134	160
Income From Continuing Operations Before Income Taxes	354	528	725	444
Income Taxes	135	216	273	170
Income From Continuing Operations	219	312	452	274
Discontinued Operations (Net of Income Taxes) (Note 8)	2	(8)	2	-
Net Income	$ 221	$ 304	$ 454	$ 274
Basic Earnings Per Share of Common Stock:				
Income From Continuing Operations	$ 0.67	$ 0.94	$ 1.40	$ 0.85
Discontinued Operations	-	(0.02)	0.01	-
Net Earnings Per Basic Share	$ 0.67	$ 0.92	$ 1.41	$ 0.85
Diluted Earnings Per Share of Common Stock:				
Income From Continuing Operations	$ 0.67	$ 0.93	$ 1.39	$ 0.84
Discontinued Operations	-	(0.02)	0.01	-
Net Earnings Per Diluted Share	$ 0.67	$ 0.91	$ 1.40	$ 0.84

FIRSTENERGY CORP.

CONSOLIDATED FINANCIAL AND PRO FORMA COMBINED OPERATING STATISTICS
(Unaudited)

For the Years Ended December 31,	2007	2006	2005	2004	2003	2002	1997
GENERAL FINANCIAL INFORMATION							
(Dollars in millions)							
Revenues	$ 12,802	$ 11,501	$ 11,358	$ 11,600	$ 10,802	$10,527	$2,961
Net Income	$ 1,309	$ 1,254	$ 861	$ 878	$ 423	$553	$306
SEC Ratio of Earnings to							
Fixed Charges	3.21	3.14	2.74	2.64	1.75	1.88	2.18
Capital Expenditures	$1,496	$1,170	$1,144	$731	$792	$904	$188
Total Capitalization	$ 17,846	$ 17,570	$ 17,527	$18,938	$18,414	$18,686	$12,124
Capitalization Ratios:							
Common Stockholders' Equity	50.3 %	51.4 %	52.4 %	45.3 %	45.0 %	37.7 %	34.3 %
Preferred and Preference Stock:							
Not Subject to Mandatory Redemption	-	-	1.1	1.8	1.8	1.8	5.5
Subject to Mandatory Redemption	-	-	-	-	-	2.3	2.7
Long-Term Debt	49.7	48.6	46.5	52.9	53.2	58.2	57.5
Total Capitalization	100.0 %	100.0 %	100.0 %	100.0 %	100.0 %	100.0 %	100.0 %
Average Capital Costs:							
Preferred and Preference Stock	-	-	5.67%	6.51%	6.47%	7.50%	8.02%
Long-Term Debt	5.89%	6.33%	6.05%	5.93%	6.08%	6.56%	8.02%
COMMON STOCK DATA							
Earnings per Share (a):							
Basic	$ 4.27	$ 3.85	$ 2.68	$ 2.77	$ 1.46	$ 2.09	$ 1.94
Diluted	$ 4.22	$ 3.82	$ 2.67	$ 2.76	$ 1.46	$ 2.08	$ 1.94
Return on Average Common Equity (a)	14.9%	13.5%	10.0%	10.8%	5.9%	8.2%	11.0%
Dividends Paid per Share	$ 2.00	$ 1.80	$ 1.67	$ 1.50	$ 1.50	$ 1.50	$ 1.50
Dividend Payout Ratio (a)	47%	47%	62%	54%	103%	72%	77%
Dividend Yield	2.8%	3.0%	3.4%	3.8%	4.3%	4.5%	5.2%
Price/Earnings Ratio (a)	17.0	15.7	18.3	14.3	24.1	15.8	14.9
Book Value per Share	$ 29.45	$ 28.35	$ 27.98	$ 26.20	$ 25.35	$ 24.01	$ 18.71
Market Price per Share	$ 72.34	$ 60.30	$ 48.99	$ 39.51	$ 35.20	$ 32.97	$ 29.00
Ratio of Market Price to Book Value	246%	213%	175%	151%	139%	137%	155%
OPERATING STATISTICS (b)							
Generation Kilowatt-Hour Sales (Millions):							
Residential	39,158	37,618	34,716	31,781	31,322	31,937	30,653
Commercial	36,879	35,390	32,878	32,114	32,311	32,892	30,149
Industrial	33,476	34,309	32,907	31,675	32,451	32,726	36,531
Other	540	542	547	504	554	531	612
Total Retail	110,053	107,859	101,048	96,074	96,638	98,086	97,945
Total Wholesale	24,114	23,083	28,521	53,268	42,059	30,007	11,657
Total Sales	134,167	130,942	129,569	149,342	138,697	128,093	109,602
Customers Served:							
Residential	3,956,837	3,959,043	3,941,030	3,916,855	3,874,052	3,868,499	3,708,760
Commercial	517,251	514,056	509,933	500,695	496,253	471,440	444,582
Industrial	10,367	10,458	10,637	10,597	10,871	18,416	21,028
Other	6,054	6,356	6,124	5,654	5,635	5,716	5,835
Total	4,490,509	4,489,913	4,467,724	4,433,801	4,386,811	4,364,071	4,180,205
Number of Employees	14,534	13,739	14,586	15,245	15,905	17,560	18,867

(a) Before discontinued operations in 2006, 2005, 2004, 2003 and 2002, and accounting changes in 2005 and 2003.

(b) Reflects pro forma combined Ohio Edison, Centerior and GPU statistics in 1997.

END