WISCONSIN ENERGY CORP
Form 10-K
February 28, 2008

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

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

For the Fiscal Year Ended

December 31, 2007

Commission File Number	Registrant; State of Incorporation Address; and Telephone Number	IRS Employer Identification No.
001-09057	WISCONSIN ENERGY CORPORATION (A Wisconsin Corporation) 231 West Michigan Street P.O. Box 1331 Milwaukee, WI 53201 (414) 221-2345	39-1391525

Securities Registered Pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, $.01 Par Value	New York Stock Exchange

Securities Registered Pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes [X] No [ ]

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act. Yes [ ] No [X]

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes [X] No [ ]

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (Section 229.405 of this Chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in the definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [ ]

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer, "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer [X]	Accelerated filer [ ]
Non-accelerated filer [ ] (Do not check if a smaller reporting company)	Smaller reporting company [ ]

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes [ ] No [X]

The aggregate market value of the common stock of Wisconsin Energy Corporation held by non-affiliates was approximately $5.2 billion based upon the reported closing price of such securities as of June 30, 2007.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date (January 31, 2008):

Common Stock, $.01 Par Value, 116,933,966, shares outstanding

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Documents Incorporated by Reference

Portions of Wisconsin Energy Corporation's definitive Proxy Statement on Schedule 14A for its Annual Meeting of Stockholders, to be held on May 1, 2008, are incorporated by reference into Part III hereof.

WISCONSIN ENERGY CORPORATION

FORM 10-K REPORT FOR THE YEAR ENDED DECEMBER 31, 2007

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DEFINITION OF ABBREVIATIONS AND INDUSTRY TERMS

The abbreviations and terms set forth below are used throughout this report and have the meanings assigned to them below.

Wisconsin Energy Subsidiaries and Affiliates

Primary Subsidiaries

Edison Sault

Edison Sault Electric Company

We Power

W.E. Power, LLC

Wisconsin Electric

Wisconsin Electric Power Company

Wisconsin Gas

Wisconsin Gas LLC

Significant Assets

OC 1

Oak Creek expansion Unit 1

OC 2

Oak Creek expansion Unit 2

Point Beach

Point Beach Nuclear Plant

PWGS

Port Washington Generating Station

PWGS 1

Port Washington Generating Station Unit 1

PWGS 2

Port Washington Generating Station Unit 2

Other Affiliates

ATC

American Transmission Company LLC

Calumet

Calumet Energy

Minergy

Minergy LLC

Minergy Neenah

Minergy Neenah, LLC

NMC

Nuclear Management Company, LLC

WICOR

Wicor, Inc.

Wispark

Wispark LLC

Wisvest

Wisvest LLC

Federal and State Regulatory Agencies

DOA

Wisconsin Department of Administration

DOE

United States Department of Energy

EPA

United States Environmental Protection Agency

FERC

Federal Energy Regulatory Commission

IRS

Internal Revenue Service

MPSC

Michigan Public Service Commission

NRC

United States Nuclear Regulatory Commission

PSCW

Public Service Commission of Wisconsin

SEC

Securities and Exchange Commission

WDNR

Wisconsin Department of Natural Resources

Environmental Terms

Act 141

2005 Wisconsin Act 141

Air Permit

Air Pollution Control Construction Permit

BART

Best Available Retrofit Technology

BTA

Best Technology Available

CAA

Clean Air Act

CAIR

Clean Air Interstate Rule

CAMR

Clean Air Mercury Rule

CAVR

Clean Air Visibility Rule

CERCLA

Comprehensive Environmental Response, Compensation and Liability Act

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DEFINITION OF ABBREVIATIONS AND INDUSTRY TERMS

The abbreviations and terms set forth below are used throughout this report and have the meanings assigned to them below.

CO_2	Carbon Dioxide
CWA	Clean Water Act
NAAQS	National Ambient Air Quality Standard
NO_x	Nitrogen Oxide

$PM_{2.5}$	Fine Particulate Matter
RI/FS	Remedial Investigation and Feasibility Study
SO_2	Sulfur Dioxide
WPDES	Wisconsin Pollution Discharge Elimination System

Other Terms and Abbreviations

ALJ	Wisconsin Administrative Law Judge
Compensation Committee	Compensation Committee of the Board of Directors
CPCN	Certificate of Public Convenience and Necessity
D&D Fund	Uranium Enrichment Decontamination and Decommissioning Fund
Energy Policy Act	Energy Policy Act of 2005
Fitch	Fitch Ratings
FPL	FPL Group, Inc.
FTRs	Financial Transmission Rights
Guardian	Guardian Pipeline L.L.C.
GCRM	Gas Cost Recovery Mechanism
GDP	Gross Domestic Product
Junior Notes	Wisconsin Energy's 2007 Series A Junior Subordinated Notes due 2067 issued in May 2007
LLC	Limited Liability Company
LMP	Locational Marginal Price
LSEs	Load Serving Entities
MAIN	Mid-America Interconnected Network, Inc.
MISO	Midwest Independent Transmission System Operator, Inc.
MISO Energy Markets	

	MISO bid-based energy market
Moody's	Moody's Investor Service
PJM	PJM Interconnection, L.L.C.
PRSG	Planning Reserve Sharing Groups
PSEG	Public Service Enterprise Group
PTF	Power the Future
PUHCA 1935	Public Utility Holding Company Act of 1935, as amended
PUHCA 2005	Public Utility Holding Company Act of 2005
RCC	Replacement Capital Covenant dated May 11, 2007
RFC	Reliability First Corporation
RSG	Revenue Sufficiency Guarantee
RTO	Regional Transmission Organizations
S&P	Standard & Poor's Ratings Services

Measurements

Btu	British thermal unit(s)
Dth	Dekatherm(s) (One Dth equals one million Btu)
kW	Kilowatt(s) (One kW equals one thousand watts)
kWh	Kilowatt-hour(s)
MW	Megawatt(s) (One MW equals one million watts)

DEFINITION OF ABBREVIATIONS AND INDUSTRY TERMS

The abbreviations and terms set forth below are used throughout this report and have the meanings assigned to them below.

MWh	Megawatt-hour(s)
Watt	A measure of power production or usage

Accounting Terms

AFUDC	Allowance for Funds Used During Construction
APB	Accounting Principles Board
ARO	Asset Retirement Obligation
CWIP	Construction Work in Progress
FASB	Financial Accounting Standards Board
FIN	FASB Interpretation
FSP	FASB Staff Position
GAAP	Generally Accepted Accounting Principles
NOLs	Net Operating Loss Carryforwards
OPEB	Other Post-Retirement Employee Benefits
SFAS	Statement of Financial Accounting Standards

Accounting Pronouncements

FIN 46	Consolidation of Variable Interest Entities
FIN 46R	Consolidation of Variable Interest Entities (Revised 2003)
FIN 47	Accounting for Conditional Asset Retirement Obligations
FIN 48	Accounting for Uncertainty in Income Taxes
FSP SFAS 106-2	Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization

	Act of 2003
FSP FIN 46R-6	Determining the Variability to Be Considered in Applying FIN 46R
SFAS 34	Capitalization of Interest Cost
SFAS 71	Accounting for the Effects of Certain Types of Regulation
SFAS 87	Employers' Accounting for Pensions
SFAS 106	Employers' Accounting for Postretirement Benefits Other Than Pensions
SFAS 109	Accounting for Income Taxes
SFAS 115	Accounting for Certain Investments in Debt and Equity Securities
SFAS 123	Accounting for Stock-Based Compensation
SFAS 123R	Share-Based Payment (Revised 2004)
SFAS 133	Accounting for Derivative Instruments and Hedging Activities
SFAS 142	Goodwill and Other Intangible Assets
SFAS 143	Accounting for Asset Retirement Obligations
SFAS 144	Accounting for the Impairment or Disposal of Long-Lived Assets
SFAS 149	Amendment of SFAS 133 on Derivative Instruments and Hedging Activities
SFAS 157	Fair Value Measurements
SFAS 158	Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans
SFAS 159	The Fair Value Option for Financial Assets and Financial Liabilities

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

Certain statements contained in this report are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. These statements are based upon management's current expectations and are subject to risks and uncertainties that could cause our actual results to differ materially from those contemplated in the statements. Readers are cautioned not to place undue reliance on these forward-looking statements. Forward-looking statements include, among other things, statements concerning management's expectations and projections regarding earnings, completion of construction projects, regulatory matters, fuel costs, sources of electric energy supply, coal and gas deliveries, remediation costs, environmental and other capital expenditures, liquidity and capital resources and other matters. In some cases, forward-looking statements may be identified by reference to a future period or periods or by the use of forward-looking terminology such as "anticipates," "believes," "estimates," "expects," "forecasts," "guidance," "intends," "may," "objectives," "plans," "possible," "potential," "projects" or similar terms or variations of these terms.

Actual results may differ materially from those set forth in forward-looking statements. In addition to the assumptions and other factors referred to specifically in connection with these statements, factors that could cause our actual results to differ materially from those contemplated in any forward-looking statements or otherwise affect our future results of operations and financial condition include, among others, the following:

- Factors affecting utility operations such as unusual weather conditions; catastrophic weather-related or terrorism-related damage; availability of electric generating facilities; unscheduled generation outages, or unplanned maintenance or repairs; unanticipated events causing scheduled generation outages to last longer than expected; unanticipated changes in fossil fuel, purchased power, coal supply, gas supply or water supply costs or availability due to higher demand, shortages, transportation problems or other developments; nonperformance by electric energy or natural gas suppliers under existing power purchase or gas supply contracts; environmental incidents; electric transmission or gas pipeline system constraints; unanticipated organizational structure or key personnel changes; collective bargaining agreements with union employees or work stoppages; or inflation rates.

- Increased competition in our electric and gas markets and continued industry consolidation.

- Timing, resolution and impact of pending and future rate cases and negotiations, including recovery for new investments as part of our PTF strategy, environmental compliance, transmission service, fuel costs and costs associated with the implementation of the MISO Energy Markets.

- Regulatory factors such as changes in rate-setting policies or procedures; changes in regulatory accounting policies and practices; industry restructuring initiatives; transmission or distribution system operation and/or administration initiatives; required changes in facilities or operations to reduce the risks or impacts of potential terrorist activities; required approvals for new construction; and the siting approval process for new generation and transmission facilities and new pipeline construction.

- Factors affecting the economic climate in our service territories such as customer growth; customer business conditions, including demand for their products and services; and changes in market demand and demographic patterns.

- Factors which impede execution of our PTF strategy, including receipt of necessary state and federal regulatory approvals and permits; timely and successful resolution of legal challenges, including current challenges to the WPDES permit for the Oak Creek expansion; opposition to siting of new generating facilities; the adverse interpretation or enforcement of permit conditions by the permitting agencies; and obtaining the investment capital from outside sources necessary to implement the strategy.

- The impact of recent and future federal, state and local legislative and regulatory changes, including electric and gas industry restructuring initiatives; implementation of the Energy Policy Act; changes in allocation of energy assistance, including state public benefits funds; changes in environmental, tax and other laws and regulations to which we are subject; and changes in the application of existing laws and regulations.

- Restrictions imposed by various financing arrangements and regulatory requirements on the ability of our subsidiaries to transfer funds to us in the form of cash dividends, loans or advances.

- The cost and other effects of legal and administrative proceedings, settlements, investigations, claims and changes in those matters.

- Factors affecting the availability or cost of capital such as, changes in interest rates and other general capital market conditions; our capitalization structure; market perceptions of the utility industry, us or any of our subsidiaries; or our credit ratings.

- The investment performance of our pension and other post-retirement benefit plans.

- The effect of accounting pronouncements issued periodically by standard setting bodies.

- Unanticipated technological developments that result in competitive disadvantages and create the potential for impairment of existing assets.

- Changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading markets and fuel suppliers and transporters.

- The performance of projects undertaken by our non-utility businesses and the success of efforts to invest in and develop new opportunities.

- The cyclical nature of property values that could affect our real estate investments.

- Changes to the legislative or regulatory restrictions or caps on non-utility acquisitions, investments or projects, including the State of Wisconsin's public utility holding company law.

- Other business or investment considerations that may be disclosed from time to time in our SEC filings or in other publicly disseminated written documents, including the risk factors set forth in Item 1A of this report.

Wisconsin Energy Corporation expressly disclaims any obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

PART I

ITEM 1. BUSINESS

INTRODUCTION

Wisconsin Energy Corporation was incorporated in the State of Wisconsin in 1981 and became a diversified holding company in 1986. We maintain our principal executive offices in Milwaukee, Wisconsin. Unless qualified by their context when used in this document, the terms Wisconsin Energy, the Company, our, us or we refer to the holding company and all of its subsidiaries.

We conduct our operations primarily in two operating segments: a utility energy segment and a non-utility energy segment. Our primary subsidiaries are Wisconsin Electric, Wisconsin Gas, Edison Sault and We Power.

Utility Energy Segment:

Our utility energy segment consists of: Wisconsin Electric, Wisconsin Gas and Edison Sault. We serve approximately 1,132,500 electric customers in Wisconsin and the Upper Peninsula of Michigan. We have approximately 1,049,500 gas customers in Wisconsin, 470 steam customers in metropolitan Milwaukee, Wisconsin, and 3,040 water customers in suburban Milwaukee, Wisconsin. Wisconsin Electric and Wisconsin Gas operate under the trade name of "We Energies".

Non-Utility Energy Segment:

Our non-utility energy segment consists primarily of We Power. We Power was formed in 2001 to design, construct, own and lease to Wisconsin Electric the new generating capacity included in our PTF strategy. See Item 7 for more information on PTF.

Discontinued Operations:

In September 2006, we sold 100% of our membership interests in Minergy Neenah. Previously, Minergy Neenah's operations were included in Corporate and Other. We sold our Calumet facility, which was part of our non-utility energy segment, in May 2005.

PTF Strategy:

In September 2000, we announced our PTF strategy to improve the supply and reliability of electricity in Wisconsin. As part of our PTF strategy, we are: (1) investing in new natural gas-fired and coal-fired electric generating facilities, (2) upgrading Wisconsin Electric's existing electric generating facilities and (3) investing in upgrades of our existing energy distribution system. Also, as part of this strategy, we announced and began implementing plans to divest non-core assets and operations in our non-utility energy segment and to reduce our real estate operations. Additional information concerning PTF may be found below under Non-Utility Energy Segment, as well as in Item 7.

For further financial information about our business segments, see Results of Operations in Item 7 and Note Q -- Segment Reporting in the Notes to Consolidated Financial Statements in Item 8.

Our annual and periodical filings to the SEC are available, free of charge, through our Internet website www.wisconsinenergy.com. These documents are available as soon as reasonably practicable after such materials are filed (or furnished) with the SEC.

UTILITY ENERGY SEGMENT

ELECTRIC UTILITY OPERATIONS

Our electric utility operations consist of the electric operations of Wisconsin Electric and Edison Sault. Wisconsin Electric, which is the largest electric utility in the State of Wisconsin, generates and distributes electric energy in a territory in southeastern (including the metropolitan Milwaukee area), east central and northern Wisconsin and in the Upper Peninsula of Michigan. Edison Sault generates and distributes electric energy in a territory in the eastern Upper Peninsula of Michigan.

Effective April 1, 2005, Wisconsin Electric and Edison Sault began to participate in the MISO Energy Markets which changed how our generating units are dispatched and how we buy and sell power. For further information, see Factors Affecting Results, Liquidity and Capital Resources in Item 7.

Electric Sales

Our electric energy sales to all classes of customers, excluding intercompany sales between Edison Sault and Wisconsin Electric, totaled approximately 33.0 million MWh during 2007 and approximately 31.9 million MWh during 2006. We had approximately 1,132,500 electric customers at December 31, 2007 and 1,125,200 electric customers at December 31, 2006.

Wisconsin Electric:

Wisconsin Electric is authorized to provide retail electric service in designated territories in the State of Wisconsin, as established by indeterminate permits, CPCNs or boundary agreements with other utilities, and in certain territories in the State of Michigan pursuant to franchises granted by municipalities. Wisconsin Electric also sells wholesale electric power within the MISO Energy Markets.

Edison Sault:

Edison Sault is authorized to provide retail electric service in certain territories in the State of Michigan pursuant to franchises granted by municipalities. Edison Sault also provides wholesale electric service under contract with one rural cooperative.

Electric Sales Growth:

We presently anticipate total retail and municipal electric kWh sales of our utility energy segment will grow at an annual rate of 1.0% to 1.5% over the next five years. This estimate excludes our largest customers, two iron ore mines, and assumes moderate growth in the economy of our electric utility service territories and normal weather. We also anticipate that our peak electric demand will grow at a rate of 1.5% to 2.0% over the next five years.

Sales to Large Electric Retail Customers:

Wisconsin Electric provides electric utility service to a diversified base of customers in such industries as mining, paper, foundry, food products and machinery production, as well as to large retail chains. Edison Sault provides electric service to industrial accounts in the paper, crude oil pipeline and limestone quarry industries, as well as to several state and federal government facilities.

Our largest retail electric customers are two iron ore mines located in the Upper Peninsula of Michigan. Wisconsin Electric had special negotiated power-sales contracts with these mines that expired in December 2007. The combined electric energy sales to the two mines accounted for 6.3% and 6.2% of our total electric utility energy sales during 2007 and 2006, respectively. In 2005, the mines notified us that they were disputing certain billings and placed the disputed amounts in escrow. In May 2007, Wisconsin Electric entered into a settlement agreement with the two iron ore mines. The settlement was a full and complete resolution of all claims and disputes between the parties for electric service rendered by Wisconsin Electric under the power purchase agreements through March 31, 2007. The MPSC approved the settlement in May 2007. Pursuant to the settlement, the mines paid Wisconsin Electric approximately $9.0 million and Wisconsin Electric released to the mines all funds held in escrow. The earnings impact of the payment from the mines was $0.04 per share. The settlement also provided a mutually satisfactory pricing structure through December 31, 2007. Beginning January 1, 2008, the mines became eligible to receive electric service from Wisconsin Electric in accordance with tariffs approved by the MPSC.

Sales to Wholesale Customers:

During 2007, Wisconsin Electric sold wholesale electric energy to two municipally owned systems, two rural cooperatives and one municipal joint action agency located in the states of Wisconsin and Michigan. Wholesale electric energy sales by Wisconsin Electric were also made to 9 other public utilities and power marketers throughout the region under rates approved by FERC. Edison Sault sold wholesale electric energy to one rural cooperative during 2007. Wholesale sales accounted for approximately 10.9% of our total electric energy sales and 6.5% of total electric operating revenues during 2007, compared with 9.7% of total electric energy sales and 5.1% of total electric operating revenues during 2006.

Electric System Reliability Matters:

Electric energy sales are impacted by seasonal factors and varying weather conditions from year-to-year. As a summer peaking utility, the summer period is the most relevant period for capacity planning purposes for us as a result of cooling load. Prior to 2006, Wisconsin Electric was a member of the MAIN reliability council, whose guidelines required a minimum 14% planning reserve margin for the short-term (up to one year ahead). Effective January 1, 2006, Wisconsin Electric became a member of RFC, a successor council encompassing most of the East Central Area Reliability Council and Mid-Atlantic Area Council and a portion of MAIN. The RFC has approved reliability standards, which set forth the methodology for establishing planning reserve requirements and require the formation of PRSG. Wisconsin Electric is a member of the Midwest PRSG which was formed in June 2007 to establish planning reserve requirements. Wisconsin Electric must also adhere to

PSCW guidelines requiring an 18% planning reserve margin; however, in November 2007, the PSCW opened a new docket to review the 18% planning reserve margin requirement. Wisconsin Electric cannot at this time predict the outcome of this docket and its potential impact on the current 18% requirement. The MPSC has not established guidelines in this area.

We had adequate capacity to meet all of our firm electric load obligations during 2007 and expect to have adequate capacity to meet all of our firm obligations during 2008. For additional information, see Factors Affecting Results, Liquidity and Capital Resources in Item 7.

Electric Supply

Our electric supply strategy is to provide our customers with a diverse fuel mix that is expected to maintain a stable, reliable and affordable supply of electricity. We supply electricity to our customers from power plants that we own. We supplement our internally generated power supply with long-term power purchase agreements and through spot purchases in the MISO Energy Markets.

Our installed capacity by fuel type for the years ended December 31, is shown below.

	Dependable Capability in MW (a)		
	2007	2006	2005
Coal	3,247	3,334	3,334
Nuclear (b)	-	1,036	1,036
Natural Gas - Combined Cycle (c)	575	575	545
Natural Gas/Oil - Peaking Units (d)	1,162	1,180	1,168
Renewables (e)	84	84	84
Total	5,068	6,209	6,167

(a) Dependable capability is the net power output under average operating conditions with equipment in an average state of repair as of a given month in a given year. The values were established by test and may change slightly from year to year.

(b) Concurrent with the sale of Point Beach, Wisconsin Electric entered into a power purchase agreement with the buyer to purchase all of the energy produced by Point Beach until 2030 for Unit 1 and 2033 for Unit 2.

(c) The increase in 2006 as compared to 2005, primarily reflects a 30 MW increase in dependable capability at PWGS 1, which was added in 2005, from the 545 MW guaranteed capacity required under the lease.

(d) Approximately 50% of the Natural Gas/Oil peaking units are dual-fueled. The dual-fueled facilities generally burn oil only if natural gas is not available due to constraints on the natural gas pipeline and/or at the local gas distribution company that delivers gas to the plants.

(e) Includes hydroelectric and wind generation

Our PTF strategy, which is discussed further in Item 7, includes the addition of 2,320 MW of generating capacity from 2005 through 2010. Our first plant, a natural gas combined cycle unit, providing 575 MW of dependable capability, went on line in 2005. The second 545 MW unit is expected to go on line in the second quarter of 2008. Under our PTF plan, we expect to have 515 MW of dependable capability coming in service in 2009 related to our first coal unit. The second coal unit is expected to provide us with 515 MW of dependable capability in 2010. In addition, we expect to have 145 MW of wind generation coming on line during 2008, of which only 32 MW is dependable capability.

The table below indicates our sources of electric energy supply as a percentage of sales, for the three years ended December 31, 2007, as well as an estimate for 2008.

	Estimate	Actual		
	2008	2007	2006	2005
Coal	55.6%	54.1%	54.7%	57.6%
Nuclear (a)	- %	17.3%	25.3%	20.0%
Hydroelectric	2.1%	1.1%	1.4%	1.6%
Natural Gas -Combined Cycle	5.3%	5.2%	3.5%	1.4%
Natural Gas/Oil-Peaking Units	1.2%	1.0%	0.6%	1.5%
Net Generation	64.2%	78.7%	85.5%	82.1%
Purchased Power (a)	35.8%	21.3%	14.5%	17.9%
Total	100.0%	100.0%	100.0%	100.0%

(a) In 2007, purchased power increased and nuclear generation decreased due to the sale of Point Beach and the entry into the associated power purchase agreement with the buyer.

Our average fuel and purchased power costs per MWh by fuel type for the years ended December 31 are shown below.

	2007	2006	2005
Coal	$20.52	$18.30	$14.74
Nuclear	$5.83	$5.23	$5.06
Natural Gas - Combined Cycle	$61.27	$66.30	$84.77
Natural Gas/Oil - Peaking Units	$111.21	$136.24	$125.67
Purchased Power	$45.19	$47.67	$53.59

Historically, the fuel costs for coal have been under long-term contracts, which helped with price stability. In 2006, we entered into new long-term coal contracts to replace certain contracts that expired during 2006. Coal and associated transportation services have seen greater volatility in pricing than typically experienced in these markets due to increases in the domestic and world-wide demand for coal and the impacts of higher diesel costs which are reflected in the form of fuel surcharges on rail transportation.

The costs for natural gas and purchased power, which is primarily natural gas-fired, are volatile and have experienced significant increases since 2002. Natural gas costs have increased significantly because the supply of natural gas in recent years has not kept pace with the demand. Beginning in late 2003 and concurrent with the approval by the PSCW, we established a hedging program to help manage our natural gas price risk. This hedging program is generally implemented on an 18 month forward-looking basis. Proceeds related to the natural gas hedging program are reflected in the 2007, 2006 and 2005 average costs of natural gas and purchased power shown above. In addition, concurrent with the Point Beach sale, our purchased power costs also reflect the long-term power purchase agreement with the buyer for all of the energy produced by Point Beach.

Coal-Fired Generation

Coal Supply:

We diversify the coal supply for our power plants by purchasing coal from mines in northern and central Appalachia as well as from various western mines. During 2008, 100% of our projected coal requirements of 12.3 million tons are under contracts which are not tied to 2008 market pricing fluctuations. Our coal-fired generation consists of six operating plants with a dependable capability of approximately 3,247 MW.

Following is a summary of the annual tonnage amounts for our principal long-term coal contracts by the month and year in which the contracts expire.

Contract Expiration Date	Annual Tonnage
	(Thousands)
Dec. 2008	4,150.0
Dec. 2009	6,500.0
Dec. 2010	1,660.0

Coal Deliveries:

Approximately 87% of our 2008 coal requirements are expected to be delivered by Wisconsin Electric-owned or leased unit trains. The unit trains will transport coal for the Oak Creek, Pleasant Prairie and Edgewater Power Plants from Wyoming mines. Coal from Central Appalachia and Colorado mines is also transported via rail to Lake Erie or Lake Michigan transfer docks and delivered to the Valley and Milwaukee County Power Plants. Montana and Wyoming coal for Presque Isle Power Plant is transported via rail to Superior, Wisconsin, placed in dock storage and reloaded into lake vessels for plant delivery. Central Appalachia and Colorado coal bound for the Presque Isle Power Plant is shipped via rail to Lake Erie and Lake Michigan (Chicago) coal transfer docks, respectively, for lake vessel delivery to the plant.

Environmental Matters:

For information regarding emission restrictions, especially as they relate to coal-fired generating facilities, see Factors Affecting Results, Liquidity and Capital Resources -- Environmental Matters in Item 7.

Nuclear Generation

Point Beach:

Prior to September 28, 2007, Wisconsin Electric owned two 518 MW electric generating units at Point Beach in Two Rivers, Wisconsin. On September 28, 2007, Wisconsin Electric sold Point Beach to an affiliate of FPL for approximately $924 million. Pursuant to the terms of the sale agreement, the buyer purchased Point Beach, its nuclear fuel, associated inventories and assumed the obligation to decommission the plant.

A long-term power purchase agreement with the buyer became effective upon closing of the sale. Pursuant to this agreement, Wisconsin Electric is purchasing all of the energy produced by Point Beach. The power purchase agreement extends through 2030 for Unit 1 and 2033 for Unit 2. Based on the agreement, we will be paying the buyer a predetermined price per MWh for energy delivered. For additional information on the sale of Point Beach, see Nuclear Operations under Factors Affecting Results, Liquidity and Capital Resources in Item 7 of this report.

Nuclear Management Company:

Prior to the Point Beach sale, we had a partial ownership in NMC. NMC held the operating licenses for Point Beach. Upon the sale of Point Beach, NMC transferred the operating licenses to the buyer and our relationship with NMC was terminated.

Used Nuclear Fuel Storage & Disposal:

For information concerning used nuclear fuel storage and disposal issues, see Factors Affecting Results, Liquidity and Capital Resources in Item 7.

For further information on the sale of Point Beach, see Note D -- Asset Sales, Divestitures and Discontinued Operations in the Notes to Consolidated Financial Statements in Item 8.

Natural Gas-Fired Generation

Our natural gas-fired generation consists of five operating plants with a dependable capability of approximately 1,475 MW at December 31, 2007. In July 2005, we added PWGS 1, a natural gas-fired unit with a dependable capability of 575 MW. A second 545 MW unit at PWGS is expected to come on line in 2008.

We purchase natural gas for these plants on the spot market from gas marketers, utilities and producers and we arrange for transportation of the natural gas to our plants. We have firm and interruptible transportation, balancing and storage agreements intended to support the plants' variable usage.

The PSCW has approved a program that allows us to hedge up to 75% of our estimated gas usage for electric generation in order to help manage our natural gas price risk. The costs of this program are included in our fuel and purchased power costs.

Oil-Fired Generation

Fuel oil is used for the combustion turbines at the Germantown Power Plants units 1-4. It is also used for boiler ignition and flame stabilization at the Presque Isle Power Plant. Our oil-fired generation had a dependable capability of approximately 262 MW at December 31, 2007. The natural gas facilities generally burn oil only if natural gas is not available due to constraints on the natural gas pipeline and/or at the local gas distribution company that delivers gas to the plants. Fuel oil requirements are purchased under agreements with suppliers.

Renewable Generation

Wisconsin Electric:

Wisconsin Electric's hydroelectric generating system consists of thirteen operating plants with a total installed capacity of approximately 88 MW and a dependable capability of approximately 57 MW at December 31, 2007. Of these thirteen plants, twelve plants (86 MW of installed capacity) have long-term licenses from FERC. The thirteenth plant, with an installed generating capacity of approximately 2 MW, does not require a license.

Wisconsin Electric holds development rights for two wind farm projects and began the construction of the first project in 2007. Additional information on wind generation is provided in Factors Affecting Results, Liquidity and Capital Resources -- Other Utility Rate Matters -- Wind Generation in Item 7.

Edison Sault:

Edison Sault's primary source of generation is its hydroelectric generating plant located on the St. Mary's River in Sault Ste. Marie, Michigan. The hydroelectric generating plant has a total dependable capability of approximately 27 MW. The water for this facility is leased under a contract with the United States Army Corps of Engineers with tenure to December 31, 2050. However, the Secretary of the Army has the right to terminate the contract subsequent to December 2025 by providing at least a five-year termination notice. No such notice can be given prior to December 31, 2020. Edison Sault pays for all water taken from the St. Mary's River at predetermined rates with a minimum annual payment of $0.1 million. The total flow of water taken out of Lake Superior, which in effect is the flow of water in the St. Mary's River, is under the direction and control of the International Joint Commission, created by the Boundary Water Treaty of 1909 between the United States and Great Britain, now represented by Canada.

Hydroelectric generation is also purchased by Edison Sault under contract from the United States Army Corps of Engineers' hydroelectric generating plant located within the Soo Locks complex on the St. Mary's River in Sault Ste. Marie, Michigan. This 17 MW contract has tenure to November 1, 2040 and cannot be terminated by the United States government prior to November 1, 2030.

Power Purchase Commitments

We enter into short and long-term power purchase commitments to meet a portion of our anticipated electric energy supply needs. The following table identifies our power purchase commitments at December 31, 2007 with unaffiliated parties for the next five years:

Year	MW Under Power Purchase Commitments
2008	1,715
2009	1,597
2010	1,597
2011	1,642
2012	1,528

Approximately 1,000 MW per year relates to the Point Beach long-term power purchase agreement related to Point Beach. Under this agreement, we will pay a predetermined price per MWh for energy delivered according to a schedule included in the agreement. The majority of the balance of these power purchase commitments are tolling arrangements whereby we are responsible for the procurement, delivery and cost of natural gas fuel related to specific units identified in the contracts. A small amount of these purchases are tied to the costs of natural gas.

Electric Transmission and Energy Markets

American Transmission Company

: ATC owns, maintains, monitors and operates electric transmission systems in Wisconsin, Michigan and Illinois. ATC's sole business is to provide reliable, economic electric transmission service to all customers in a fair and equitable manner. ATC is expected to provide comparable service to all customers, including Wisconsin Electric and Edison Sault, and to support effective competition in energy markets without favoring any market participant. ATC is regulated by FERC for all rate terms and conditions of service and is a transmission-owning member of MISO. MISO maintains operational control of ATC's transmission system, and Wisconsin Electric and Edison Sault are non-transmission owning members and customers of MISO.

We owned approximately 26.9% and 29.4% of ATC as of December 31, 2007 and 2006, respectively. Our ownership has decreased in recent years as other owners have invested additional equity in ATC related to specific, large construction projects subject to their contractual rights.

MISO:

In connection with its status as a FERC approved RTO, MISO developed bid-based energy markets, the MISO Energy Markets, which were implemented on April 1, 2005. For further information on MISO and the MISO Energy Markets, see Factors Affecting Results, Liquidity and

Capital Resources in Item 7.

Electric Hedging Program:

We purchase some of the electricity needed to satisfy our current sales obligations in the MISO Energy Markets. Due to volatility in the price of market-based energy, we face potential financial exposure. We have PSCW approval to hedge up to 75% of a future month's predicted electricity need. This plan seeks to manage market price risk, as well as, reduce price risks related to forced outages.

We also seek to mitigate the risk of price increases in coal transportation costs for coal used in our coal-fired generating facilities. The coal transportation price changes are tied to changes in a diesel fuel price index. Therefore, we generally use financial heating oil contracts to mitigate this risk. This approach is similar to the way we currently manage our natural gas supply prices. See "Hedging Gas Supply Prices" below for information on our natural gas hedging program.

Renewable Electric Energy

We have committed to significantly increase the amount of renewable energy generation we utilize. In addition, Wisconsin Electric has an "*Energy For Tomorrow®*" renewable energy program to provide our customers the opportunity to purchase energy from renewable resources. In March 2006, Wisconsin enacted new public benefits legislation, Act 141, which changes the renewable energy requirements for utilities. Act 141 requires Wisconsin utilities to provide 2% more of their total retail energy from renewable resources than their current levels by 2010, and 6% more renewable energy than their current levels by 2015. Act 141 establishes a statewide goal that 10% of all electricity in Wisconsin be generated by renewable resources by December 31, 2015. For further information on Act 141 and current renewable projects, see Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters - Renewables, Efficiency and Conservation and Utility

Rates and Regulatory Matters - Wind Generation in Item 7.

Electric Utility Operating Statistics

The following table shows certain electric utility operating statistics from 2003 to 2007 for electric operating revenues, MWh sales and customer data:

SELECTED CONSOLIDATED ELECTRIC UTILITY OPERATING DATA

Year Ended December 31	2007	2006	2005	2004	2003
Operating Revenues (Millions)					
Residential	$929.6	$883.2	$827.6	$731.3	$715.5
Small Commercial/Industrial	861.7	814.8	746.1	668.0	642.0

	676.9				519.3
Large Commercial/Industrial		647.5	602.4	549.9	
Other - Retail	19.7	19.3	17.9	17.0	16.8
Total Retail Sales	2,487.9	2,364.8	2,194.0	1,966.2	1,893.6
Wholesale - Other	95.1	78.0	94.7	73.7	68.1
Resale - Utilities	81.6	51.2	21.3	24.6	24.0
Other Operating Revenues	41.1	35.4	39.7	34.5	27.9
Total Operating Revenues	$2,705.7	$2,529.4	$2,349.7	$2,099.0	$2,013.6
MWh Sales (Thousands)					
Residential	8,586.6	8,322.7	8,562.7	8,053.9	8,099.3
Small Commercial/Industrial	9,430.3	9,142.2	9,192.7	8,840.4	8,740.6
Large Commercial/Industrial	11,245.6	11,173.1	11,687.5	11,686.4	11,401.8
Other - Retail	168.7	169.9	171.7	174.9	175.7
Total Retail Sales	29,431.2	28,807.9	29,614.6	28,755.6	28,417.4
Wholesale - Other	2,178.5	2,057.6	2,541.9	2,230.6	2,050.2
Resale - Utilities	1,434.5	1,025.7	313.7	662.2	715.8
Total Sales	33,044.2	31,891.2	32,470.2	31,648.4	31,183.4
Customers - End of Year (Thousands)					
Residential	1,015.0	1,009.7	1,001.7	992.3	980.5
Small Commercial/Industrial	114.4	112.3	110.5	108.7	106.9
Large Commercial/Industrial	0.7	0.7	0.7	0.7	0.7
Other	2.4	2.5	2.4	2.4	2.4
Total Customers	1,132.5	1,125.2	1,115.3	1,104.1	1,090.5
Customers - Average (Thousands)	1,128.5	1,120.5	1,109.7	1,096.8	1,083.1
Degree Days (a)					
Heating (6,627 Normal)	6,508	6,043	6,628	6,663	7,063
			949		
Cooling (722 Normal)	800	723		442	606

(a) As measured at Mitchell International Airport in Milwaukee, Wisconsin. Normal degree days are based upon a 20-year moving average.

GAS UTILITY OPERATIONS

Our gas utility operations consist of Wisconsin Gas and the gas operations of Wisconsin Electric. Both companies are authorized to provide retail gas distribution service in designated territories in the State of Wisconsin, as

established by indeterminate permits, CPCNs, or boundary agreements with other utilities. The two companies also transport customer-owned gas. Wisconsin Gas, the largest natural gas distribution utility in Wisconsin, operates throughout the state, including the City of Milwaukee. Wisconsin Electric's gas utility operates in three distinct service areas: west and south of the City of Milwaukee, the Appleton area and areas within Iron and Vilas Counties, Wisconsin.

Gas Deliveries

Our gas utility business is highly seasonal due to the heating requirements of residential and commercial customers. Annual gas sales are also impacted by the variability of winter temperatures.

Total gas therms delivered, including customer-owned transported gas, were approximately 2,198 million therms during 2007, an 8.3% increase compared with 2006. At December 31, 2007, we were transporting gas for approximately 1,300 customers who purchased gas directly from other suppliers. Transported gas accounted for approximately 42% of the total volumes delivered during 2007 and 2006 and 41% during 2005. We had approximately 1,049,500 gas customers at December 31, 2007, a slight increase since December 31, 2006. Our peak daily send-out during 2007 was 1,717,422 Dth on February 5, 2007.

Sales to Large Gas Customers:

We provide gas utility service to a diversified base of industrial customers who are largely within our electric service territory. Major industries served include the paper, food products and fabricated metal products industries. Fuel used for Wisconsin Electric's electric generation represents our largest transportation customer.

Gas Deliveries Growth:

We currently forecast total retail therm deliveries (excluding natural gas deliveries for generation) to stay flat over the five-year period ending December 31, 2012 as new customer additions are expected to be offset by a reduction in the average use per customer. This forecast reflects a current year normalized sales level and assumes moderate growth in the economy of our gas utility service territories and normal weather.

Competition

Competition in varying degrees exists between natural gas and other forms of energy available to consumers. A number of our large commercial and industrial customers are dual-fuel customers that are equipped to switch between natural gas and alternate fuels. We are allowed to offer lower-priced gas sales and transportation services to dual-fuel customers. Under gas transportation agreements, customers purchase gas directly from gas marketers and arrange with interstate pipelines and us to have the gas transported to their facilities. We earn substantially the same margin (difference between revenue and cost of gas) whether we sell and transport gas to customers or only transport their gas.

Our ability to maintain our share of the industrial dual-fuel market (the market that is equipped to use gas or other fuels) depends on our success and the success of third-party gas marketers in obtaining long-term and short-term supplies of natural gas at competitive prices compared to other sources and in arranging or facilitating competitively-priced transportation service for those customers that desire to buy their own gas supplies.

Federal and state regulators continue to implement policies to bring more competition to the gas industry. For information concerning proceedings by the PSCW to consider how its regulation of gas distribution utilities should change to reflect the changing competitive environment in the gas industry, see Factors Affecting Results, Liquidity and Capital Resources in Item 7. While the gas utility distribution function is expected to remain a highly regulated, monopoly function, the sales of the natural gas commodity and related services are expected to remain subject to competition from third parties. It remains uncertain if and when the current economic disincentives for small customers to choose an alternative gas commodity supplier may be removed such that we begin to face competition for the sale of gas to our smaller firm customers.

Gas Supply, Pipeline Capacity and Storage

We have been able to meet our contractual obligations with both our suppliers and our customers despite periods of severe cold and unseasonably warm weather.

Pipeline Capacity and Storage:

The interstate pipelines serving Wisconsin originate in three major gas producing areas of North America: the Oklahoma and Texas basins, the Gulf of Mexico and western Canada. We have contracted for long-term firm capacity from each of these areas. This strategy reflects management's belief that overall supply security is enhanced by geographic diversification of the supply portfolios and that Canada represents an important long-term source of reliable, competitively-priced gas.

Because of the daily and seasonal variations in gas usage in Wisconsin, we have also contracted for substantial underground storage capacity, primarily in Michigan. Storage capacity enables us to manage significant changes in daily demand and to optimize our overall gas supply and capacity costs. We generally inject gas into storage during the spring and summer months when demand is lower and withdraw it in the winter months. As a result, we can contract for less long-line pipeline capacity during periods of peak usage than would otherwise be necessary, and can purchase gas on a more uniform daily basis from suppliers year-round. Each of these capabilities enables us to reduce our overall costs. In 2007, we continued the plan started in 2006, to enter into gas purchase contracts which allow us to reduce gas inventory while maintaining supply to meet daily and seasonal demands.

We also maintain storage in the Southeast production areas, as well as in our market area. This storage capacity is designed to deliver gas when other supplies cannot be delivered during extremely cold weather in the producing areas.

We hold firm daily transportation and storage capacity entitlements from pipelines and other service providers under long-term contracts.

Term Gas Supply:

We have contracts for firm supplies with terms in excess of 30 days with suppliers for gas acquired in the Joliet, Illinois market hub and in the three producing areas discussed above. The pricing of the term contracts is based upon first of the month indices. Combined with our storage capability, management believes that the volume of gas under contract is sufficient to meet our forecasted firm peak-day demand.

Secondary Market Transactions:

Capacity release is a mechanism by which pipeline long-line and storage capacity and gas supplies under contract can be resold in the secondary market. Local distribution companies, like Wisconsin Gas and the gas operations of Wisconsin Electric, must contract for capacity and supply sufficient to meet the firm peak-day demand of their customers. Peak or near peak demand days generally occur only a few times each year. Capacity release facilitates higher utilization of contracted capacity and supply during those times when the full contracted capacity and supply are not needed by the utility, helping to mitigate the fixed costs associated with maintaining peak levels of capacity and gas supply. Through pre-arranged agreements and day-to-day electronic bulletin board postings, interested parties can purchase this excess capacity and supply. The proceeds from these transactions are passed through to rate payers, subject to the Wisconsin Electric and Wisconsin Gas GCRMs pursuant to which the companies have an opportunity to share in the cost savings. See Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters in Item 7 for information on the GCRMs. During 2007, we continued our active participation in the capacity release market.

Spot Market Gas Supply:

We expect to continue to make gas purchases in the 30-day spot market as price and other circumstances dictate. We have supply relationships with a number of sellers from whom we purchase spot gas.

Hedging Gas Supply Prices:

We have PSCW approval to hedge (i) up to 45% of planned flowing gas supply using NYMEX based natural gas options, (ii) up to 15% of planned flowing gas supply using NYMEX based natural gas future contracts and (iii) up to 35% of planned storage withdrawals using NYMEX based natural gas options. Those approvals allow both Wisconsin Electric and Wisconsin Gas to pass 100% of the hedging costs (premiums and brokerage fees) and proceeds (gains and losses) to rate payers through their respective purchase gas adjustment mechanisms. Hedge targets (volumes) are provided annually to the PSCW as part of each company's five-year gas supply plan filing.

To the extent that opportunities develop and our physical supply operating plans will support them, we also have PSCW approval to utilize NYMEX based natural gas derivatives to capture favorable forward market price differentials. That approval provides for 100% of the related proceeds to accrue to the companies' GCRMs.

Guardian:

Prior to April 2006, we had a one-third interest in Guardian. Guardian owns an interstate natural gas pipeline that runs from the Joliet, Illinois area to southeastern Wisconsin. In April 2006, we sold our one-third interest in Guardian to an unaffiliated entity. During 2006, Guardian announced a plan to extend its pipeline by approximately 110 miles from southeastern Wisconsin to Green Bay, Wisconsin. We have committed to purchase approximately 292,000 Dth per day of capacity on this extension through October 2023.

In addition, we have extended our commitment to purchase 650,000 Dth per day of capacity on the original pipeline until December 2022. In May 2007, in connection with the Guardian extension, the PSCW approved our application to construct approximately 27 miles of pipeline laterals to connect our gas distribution system to the proposed Guardian extension. In December 2007, FERC issued a CPCN to Guardian authorizing its related extension project, which is expected to be operational in November 2008.

Gas Utility Operating Statistics

The following table shows certain gas utility operating statistics from 2003 to 2007 for gas operating revenues, therms delivered and customer data.

SELECTED CONSOLIDATED GAS UTILITY OPERATING DATA

Year Ended December 31	2007	2006	2005	2004	2003
Operating Revenues (Millions)					
Residential	$934.3	$862.4	$898.9	$798.6	$769.3
Commercial/Industrial	485.4				

443.8

465.4

396.5

386.0

Interruptible

17.5

17.0

20.4

17.0

16.9

Total Retail Gas Sales

1,437.2

1,323.2

1,384.7

1,212.1

1,172.2

Transported Gas

48.4

47.8

46.3

41.4

36.6

Other Operating Revenues

(4.4)

48.9

(13.5)

	(1.1)
	17.3
Total Operating Revenues	
	$1,481.2
	$1,419.9
	$1,417.5
	$1,252.4
	$1,226.1
Therms Delivered (Millions)	
Residential	
	791.7
	727.9
	791.0
	809.9
	853.7
Commercial/Industrial	
	461.9
	435.9
	460.7
	464.0
	492.5
Interruptible	
	22.7
	21.3
	23.4
	24.7

27.5

Total Retail Gas Sales

1,276.3

1,185.1

1,275.1

1,298.6

1,373.7

Transported Gas

921.6

843.8

893.7

769.5

797.5

Total Therms Delivered

2,197.9

2,028.9

2,168.8

2,068.1

2,171.2

Customers - End of Year (Thousands)

Residential

957.9

951.0

940.7

927.4

912.0

Commercial/Industrial	
	90.2
	88.9
	87.5
	85.9
	84.7
Interruptible	
	0.1
	0.1
	0.1
	0.1
	0.1
Transported Gas	
	1.3
	1.4
	1.4
	1.4
	1.4
Total Customers	
	1,049.5
	1,041.4
	1,029.7
	1,014.8
	998.2
Customers - Average (Thousands)	
	1,042.8

	1,033.3
	1,019.8
	1,003.5
	986.7
Degree Days (a)	
Heating (6,627 Normal)	
	6,508
	6,043
	6,628
	6,663
	7,063

(

a) As measured at Mitchell International Airport in Milwaukee, Wisconsin. Normal degree days are based upon a 20-year moving average.

OTHER UTILITY OPERATIONS

Steam Utility Operations:

Wisconsin Electric's steam utility generates, distributes and sells steam supplied by its Valley and Milwaukee County Power Plants. Wisconsin Electric operates a district steam system in downtown Milwaukee and the near south side of Milwaukee. Steam is supplied to this system from Wisconsin Electric's

Valley Power Plant, a coal-fired cogeneration facility. Wisconsin Electric also operates the steam production and distribution facilities of the Milwaukee County Power Plant located on the Milwaukee County Grounds in Wauwatosa, Wisconsin.

Annual sales of steam fluctuate from year to year based upon system growth and variations in weather conditions. During 2007, the steam utility had $35.1 million of operating revenues from the sale of 2,965 million pounds of steam compared with $27.2 million of operating revenues from the sale of 2,812 million pounds of steam during 2006. As of December 31, 2007 and 2006, steam was used by approximately 470 and 460 customers, respectively, for processing, space heating, domestic hot water and humidification.

Water Utility Operations:

To leverage off of operational similarities with its natural gas business, Wisconsin Gas entered the water utility business in November 1998. As of December 31, 2007, the water utility served approximately 3,040 water customers in the suburban Milwaukee area compared with approximately 3,000 customers as of December 31, 2006. Wisconsin Gas also provides contract services to local municipalities and businesses within its service territory for water system repair and maintenance. During 2007, the water utility had $2.7 million of operating revenues compared with $2.5 million of operating revenues during 2006.

UTILITY RATE MATTERS

See Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters in Item 7.

NON-UTILITY ENERGY SEGMENT

Our non-utility energy segment is involved primarily in the design and construction of new generating capacity under our PTF strategy.

During 2000, we performed a comprehensive review of our existing portfolio of businesses and began implementing a strategy of divesting many of our non-utility energy segment businesses. Since 2000, we have sold our interest in many of our non-utility energy assets with proceeds from these sales totaling approximately $3.1 billion. As we implement our PTF strategy, we expect to grow the non-utility energy segment within the State of Wisconsin through the construction of new generating units by We Power.

We Power

We Power, through wholly owned subsidiaries, plans to design and construct in the State of Wisconsin, an additional 1,775 MW of new generating capacity in addition to the 575 MW of current dependable capacity at PWGS 1 that was put into service in July 2005. In November 2005, two unaffiliated entities purchased an ownership interest of approximately 17%, or 200 MW of capacity, in the two coal units that are being constructed in Oak Creek, Wisconsin. Similar to the generating capacity at PWGS 1, We Power will own the remaining 1,575 MW of generating capacity currently being constructed and will lease this capacity to Wisconsin Electric. At December 31, 2007, we had approximately $1,453 million of CWIP for the PTF units currently under construction. For further information about our PTF strategy, see Factors Affecting Results, Liquidity and Capital Resources -- Power the Future in Item 7.

Wisvest LLC

Wisvest was originally formed to develop, own and operate electric generating facilities and to invest in other energy-related entities. As a result of the change in corporate strategy to focus on our PTF strategy, Wisvest has discontinued its development activity. For the year ended December 31, 2007, Wisvest had $11.9 million of operating revenues from continuing operations compared with $10.0 million of operating revenues from continuing operations during 2006. We have divested substantially all of Wisvest's assets. As of December 31, 2007, Wisvest's sole operating asset and investment is Wisvest Thermal Energy Services, which provides chilled water services to the Milwaukee Regional Medical Center.

OTHER NON-UTILITY OPERATIONS

Minergy LLC

Minergy is engaged in the development and marketing of proprietary technologies designed to convert high volume industrial and municipal wastes into renewable energy and value-added products. Minergy's strategic focus is to license that technology and sell equipment to domestic and foreign operators or industrial/municipal users through its patented GlassPack® process and Glass Furnace technology as a component of larger scale waste processing solutions. We believe this licensing and equipment sale strategy will allow Minergy to recognize the economic benefits of its technology with limited capital requirements. In September 2006, we sold 100% of our membership interest in Minergy Neenah. The primary assets of Minergy Neenah were the Glass Aggregate plant and related operating contracts. For additional information on the sale of Minergy Neenah, see Note D -- Asset Sales, Divestitures and Discontinued Operations in the Notes to Consolidated Financial Statements in Item 8. Minergy's primary operation and investment at December 31, 2007 is GlassPack, LLC.

GlassPack, LLC:

The GlassPack® and Glass Furnace processes are vitrification technologies that convert various biosolids and industrial wastes into renewable energy and reusable glass aggregate thus reducing dependence on fossil fuels and the associated environmental risks. The first commercial GlassPack® facility was constructed in Zion, Illinois by the North Shore Sanitary District. The facility began operations in 2006 and is being operated by Minergy pursuant to an operations and maintenance agreement. Minergy is also pursuing other domestic and foreign GlassPack® and Glass Furnace installations through equipment sales and licensing agreements.

Wispark LLC

Wispark develops and invests in real estate. From September 30, 2000 through December 31, 2007, Wispark has reduced its overall holdings from $373.1 million to $42.5 million. During the year ended December 31, 2007, Wispark had $7.5 million of consolidated operating revenues compared with $1.1 million during 2006.

Wispark has developed several business parks primarily in southeastern Wisconsin. Wispark's flagship development, the 1,600-acre LakeView Corporate Park, which is owned through a joint venture, is located near Kenosha, Wisconsin. LakeView Corporate Park is home to approximately 80 companies located in almost 10 million square feet of buildings that have been developed on property in excess of 965 acres. Many out-of-state firms have located in this park, creating a significant number of new jobs and growth in electricity and natural gas revenues.

Other Non-Utility Subsidiaries

Other non-utility subsidiaries primarily include:

Wisconsin Energy Capital Corporation:

This entity engages in investing and financing activities. Activities include advances to affiliated companies and investments in partnerships that developed low and moderate-income housing projects.

REGULATION

Wisconsin Energy Corporation

Wisconsin Energy was an exempt holding company by order of the SEC under Section 3(a)(1) of PUHCA 1935, and, accordingly, was exempt from that law's provisions other than with respect to certain acquisitions of securities of a public utility. In August 2005, President Bush signed into law the Energy Policy Act. The Energy Policy Act repealed PUHCA 1935 and enacted PUHCA 2005, transferring jurisdiction over holding companies from the SEC to FERC. Wisconsin Energy was required to notify FERC of its status as a holding company and to seek from FERC the exempt status similar to that held under

PUHCA 1935. In March 2006, Wisconsin Energy filed with FERC notification of its status as a holding company as required and a request for exempt status similar to that held under PUHCA 1935. In June 2006, Wisconsin Energy received notice from FERC confirming its status as a holding company as required under FERC regulations implementing PUHCA 2005 and granting exempt status similar to that held under PUHCA 1935.

Non-Utility Asset Cap:

In October 1999, the Wisconsin State Legislature passed amendments to the non-utility asset cap provisions of Wisconsin's public utility holding company law. As a result, we remain subject to certain restrictions that have the potential of limiting our diversification into non-utility activities. Under the amended public utility holding company law, the sum of certain assets of all non-utility affiliates in a holding company system may not exceed 25% of the assets of all public utility affiliates. However, among other items, the amended law exempts energy-related assets and assets, like Minergy's, used for providing environmental engineering services and for processing waste materials, from being counted against the asset cap provided that they are employed in qualifying businesses. As a result of these exemptions, our non-utility assets are significantly below the non-utility asset cap as of December 31, 2007.

Under our PTF strategy, the cost of constructing new generating facilities to be owned by We Power qualifies as energy projects under the amended non-utility asset cap and therefore are entirely exempt from the definition of "non-utility" property for this purpose. The remaining cost of our PTF strategy represents investments in new and existing energy distribution system assets and upgrades to existing generation assets and has no impact on the amount of non-utility assets under the non-utility asset cap test.

Utility Energy Segment

Wisconsin Electric was an exempt holding company under Section 3(a)(1) of PUHCA 1935 and Rule 2 thereunder and, accordingly, was exempt from that law's provisions other than with respect to certain acquisitions of securities of a public utility. Due to the Energy Policy Act's enactment of PUHCA 2005 as noted above, Wisconsin Electric was also required to notify FERC of its status as a holding company by reason of its ownership interest in ATC and to seek from FERC the exempt status similar to that held under PUHCA 1935. In March 2006, Wisconsin Electric filed with FERC notification of its status as a holding company as required under FERC regulations implementing PUHCA 2005 and a request for exempt status similar to that held under PUHCA 1935. In June 2006, Wisconsin Electric received notice from FERC confirming its status as a holding company as required under FERC regulations implementing PUHCA 2005 and granting exempt status similar to that held under PUHCA 1935. For information on how rates are set for our regulated entities see Utility Rates and Regulatory Matters in Item 7.

Wisconsin Electric and Edison Sault are subject to the Energy Policy Act and the corresponding regulations developed by certain federal agencies. The Energy Policy Act, among other things, repealed PUHCA 1935 making electric utility industry consolidation more feasible, authorized FERC to review proposed mergers and the acquisition of generation facilities, changed the FERC regulatory scheme applicable to qualifying co-generation facilities and modified certain other aspects of energy regulations and Federal tax policies applicable to Wisconsin Electric and Edison Sault. Additionally, the Energy Policy Act created an Electric Reliability Organization to be overseen by FERC, which established mandatory electric reliability standards, replacing the current voluntary standards developed by the North American Electric Reliability Corporation, and has the authority to levy monetary sanctions for failure to comply with the new standards.

Wisconsin Electric and Wisconsin Gas are subject to the regulation of the PSCW as to retail electric, gas, steam and water rates in the State of Wisconsin, standards of service, issuance of securities, construction of certain new facilities, transactions with affiliates, billing practices and various other matters. Wisconsin Electric is subject to regulation of the PSCW as to certain levels of short-term debt obligations. Wisconsin Electric and Edison Sault are both subject to the regulation of the MPSC as to the various matters associated with retail electric service in the State of Michigan as noted above, except as to issuance of securities, construction of certain new facilities, levels of short-term debt obligations and advance approval of transactions with affiliates. Wisconsin Electric and Edison Sault's hydroelectric facilities are regulated by FERC. Wisconsin Electric and Edison Sault are subject to regulation of FERC with respect to wholesale power service and accounting. Edison Sault is subject to regulation of FERC with respect to the issuance of certain securities.

The following table compares the source of our utility energy segment operating revenues by regulatory jurisdiction for each of the three years in the period ended December 31, 2007.

	2007		2006		2005	
	Amount	Percent	Amount	Percent	Amount	Percent
	(Millions of Dollars)					
Wisconsin - Retail						
Electric	$2,331.1	55.1%	$2,222.4	55.9%	$2,049.7	54.0%
Gas	1,481.2	35.1%	1,419.9	35.7%	1,417.5	37.4%
Steam and Water	37.9	0.9%	29.7	0.7%	25.8	0.7%

Total	3,850.2	91.1%	3,672.0	92.3%	3,493.0	92.1%
Michigan - Retail Electric	198.0	4.7%	177.8	4.5%	184.1	4.9%
FERC - Wholesale Electric	176.6	4.2%	129.2	3.2%	115.9	3.0%
Total Utility Operating Revenues	$4,224.8	100.0%	$3,979.0	100.0%	$3,793.0	100.0%

Total flow of water to Edison Sault's hydroelectric generating plant is under the control of the International Joint Commission, created by the Boundary Water Treaty of 1909 between the United States and Great Britain, now represented by Canada. The operations of Wisconsin Electric, Wisconsin Gas and Edison Sault are also subject to regulations, where applicable, of the EPA, the WDNR, the Michigan Department of Natural Resources and the Michigan Department of Environmental Quality.

Public Benefits and Renewables

In March 2006, Wisconsin enacted new public benefits legislation, Act 141, which changes the renewable energy requirements for utilities. The law requires Wisconsin Electric to provide 2% more of its total retail energy from renewable resources than their current levels by 2010, and 6% more renewable energy than its current levels by 2015. Act 141 also redirects the administration of energy efficiency, conservation and renewable programs from the DOA back to the utilities and/or contracted third parties. In addition, Act 141 requires that 1.2% of utilities' annual operating revenues be used to fund these programs. For additional information on Act 141 and current renewable projects, see Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters - Renewables, Efficiency and Conservation and Utility Rates and Regulatory Matters - Wind Generation in Item 7.

Non-Utility Energy Segment

We Power was formed to design, construct, own and lease the new generating capacity in our PTF strategy. We Power owns the interests in the companies constructing this new generating capacity (collectively, the We Power project companies). When complete, these facilities will be leased on a long-term basis to Wisconsin Electric. We Power has received determinations from FERC that upon the transfer of the facilities by lease to Wisconsin Electric, the We Power project companies will not be deemed public utilities under the Federal Power Act and thus will not be subject to FERC's jurisdiction.

The Energy Policy Act and corresponding rules developed by FERC required us to seek FERC authorization to allow Wisconsin Electric to lease from We Power the three PTF units that are currently being constructed by We Power. In November 2006, Wisconsin Energy, Wisconsin Electric and We Power filed a joint application with FERC for authorization to transfer the generating assets and limited interconnection facilities of PWGS 2 and OC Units 1 and 2 through lease arrangements between We Power and Wisconsin Electric. We received approval from FERC on this application in December 2006. We were not required to request similar approval for the PWGS 1 lease between We Power and Wisconsin Electric as this unit was in service prior to the enactment of the Energy Policy Act.

In addition, for a short period prior to the transfer of each generation unit to Wisconsin Electric, We Power will be engaged in the sale of test power, a FERC jurisdictional transaction. We Power received approval from FERC for the sale of test power to Wisconsin Electric from PWGS 1, and for the transfer of any FERC jurisdictional facilities at Port Washington to Wisconsin Electric and/or ATC. Under Wisconsin law, We Power is not a "public utility." Environmental permits necessary for operating the facilities are the responsibility of the operating entity, Wisconsin Electric.

ENVIRONMENTAL COMPLIANCE

Environmental Expenditures

Expenditures for environmental compliance and remediation issues are included in anticipated capital expenditures described in Liquidity and Capital Resources in Item 7. For discussion of additional environmental issues, see Environmental Matters in Item 3. For further information concerning air and water quality standards and rulemaking initiated by the EPA, including estimated costs of compliance, see Factors Affecting Results, Liquidity and Capital Resources in Item 7.

Utility Energy Segment:

Compliance with federal, state and local environmental protection requirements resulted in capital expenditures by Wisconsin Electric of approximately $31 million in 2007 compared with $79 million in 2006. Expeitures incurred during 2007 primarily included costs associated with the installation of pollution abatement facilities at Wisconsin Electric's power plants. These expenditures are expected to approximate $119 million during 2008, reflecting NO_x, SO_2 and other pollution control equipment needed to comply with various rules promulgated by the EPA.

Operation, maintenance and depreciation expenses for fly ash removal equipment and other environmental protection systems are estimated to have been approximately $54 million during 2007 and $49 million during 2006.

Solid Waste Landfills

We provide for the disposal of non-ash related solid wastes and hazardous wastes through licensed independent contractors, but federal statutory provisions impose joint and several liability on the generators of waste for certain cleanup costs. Currently there are no active cases.

Coal-Ash Landfills

Some early designed and constructed coal-ash landfills may allow the release of low levels of constituents resulting in the need for various levels of remediation. Where we have become aware of these conditions, efforts have been expended to define the nature and extent of any release, and work has been performed to address these conditions. For additional information, see Note S -- Commitments and Contingencies in the Notes to Consolidated Financial Statements in Item 8. Sites currently undergoing remediation and/or monitoring include the following:

Lakeside Property:

During 2001, Wisconsin Electric completed an investigation of property that was used primarily for coal storage, fuel oil transport and coal ash disposal in support of the former Lakeside Power Plant in St. Francis, Wisconsin. Excavation and utilization of residual coal at the site, slope stabilization and cover construction have been completed. Currently, discussions are taking place with neighbors and other interested parties to determine the ultimate use of the remediated property and some other adjacent land also owned by Wisconsin Electric.

Oak Creek North Landfill:

Groundwater impairments at this landfill, located in the City of Oak Creek, Wisconsin, prompted Wisconsin Electric to investigate, during 1998, the condition of the existing cover and other conditions at the site. Surface water drainage improvements were implemented at this site during 1999 and 2000, which are expected to eliminate ash contact with water and remove unwanted ponding of water. The approved remediation plan was coordinated with activities associated with the construction of the Oak Creek expansion. Currently there is a temporary cap installed which is being used as laydown area and parking. When construction activities are completed, a permanent cap will be installed.

Manufactured Gas Plant Sites

We are reviewing and addressing environmental conditions at a number of former manufactured gas plant sites. See Note S -- Commitments and Contingencies in the Notes to Consolidated Financial Statements in Item 8.

Air Quality

See Factors Affecting Results, Liquidity and Capital Resources -- Environmental Matters in Item 7 for additional information concerning Air Quality.

Clean Water Act

See Factors Affecting Results, Liquidity and Capital Resources -- Environmental Matters in Item 7 for additional information concerning the CWA.

Greenhouse Gas Emissions

See the caption, "We may face significant costs to comply with the regulation of greenhouse gas emissions." under Item 1A Risk Factors in this report.

OTHER

Research and Development:

We had immaterial research and development expenditures in the last three years, primarily for improvement of service and abatement of air and water pollution by our electric utility operations. Research and development activities include work done by employees, consultants and contractors, plus sponsorship of research by industry associations.

Employees:

At December 31, 2007, we had the following number of employees:

	Total Employees	Represented Employees
Utility Energy Segment		
Wisconsin Electric	4,321	2,887
Wisconsin Gas	543	402
Edison Sault	62	44
Total	4,926	3,333
Non-Utility Energy Segment	33	-
Other	26	-
Total Employees	4,985	3,333

The employees represented under labor agreements were with the following bargaining units as of December 31, 2007.

	Number of Employees	Expiration Date of Current Labor Agreement
Wisconsin Electric		
Local 2150 of International Brotherhood of Electrical Workers	2,039	August 15, 2010
Local 317 of International Union of Operating Engineers	496	March 31, 2008
Local 12005 of United Steel Workers of America (a)	154	November 1, 2008
Local 510 of International Brotherhood of Electrical	155	April 30, 2010

Workers		
Local 2-0111 of Paper, Allied- Industrial Chemical & Energy Workers International Union (a)	43	November 3, 2008
Total Wisconsin Electric	2,887	
Wisconsin Gas		
Local 2150 of International Brotherhood of Electrical Workers	100	August 15, 2010
Local 7-0018 of Paper, Allied- Industrial Chemical & Energy Workers International Union (a)	144	December 31, 2010
Local 7-0018-1 of Paper, Allied- Industrial Chemical & Energy Workers International Union (a)	150	December 31, 2010
Local 7-0018-2 of Paper, Allied- Industrial Chemical & Energy Workers International Union (a)	8	February 29, 2008
Total Wisconsin Gas	402	
Edison Sault		
Local 13547 of United Steel Workers of America	44	October 22, 2010
Total Edison Sault	44	
Total Employees	3,333	

(a) Effective January 1, 2006, these bargaining units became a part of Local 2006. These former locals are now individual bargaining units of Local 2006.

ITEM 1A.
RISK FACTORS

Our business is significantly impacted by governmental regulation.

We are subject to significant state, local and federal governmental regulation. We are subject to the regulation of the PSCW as to retail electric, gas and steam rates in the State of Wisconsin, standards of service, issuance of securities, short-term debt obligations, construction of certain new facilities, transactions with affiliates, billing practices and various other matters. In addition, we are subject to the regulation of the MPSC as to the various matters associated with retail electric service in the State of Michigan, except as to issuance of securities, construction of certain new facilities, levels of short-term debt obligations and advance approval of transactions with affiliates. Further, our hydroelectric facilities are regulated by FERC, and FERC also regulates our wholesale power service practices and electric reliability requirements. Our significant level of regulation imposes restrictions on our operations and causes us to incur substantial compliance costs.

We are obligated in good faith to comply with all applicable governmental rules and regulations. If it is determined that we failed to comply with any applicable rules or regulations, whether through new interpretations or applications of the regulations or otherwise, we may be liable for customer refunds, penalties and other amounts, which could materially and adversely affect our results of operations and financial condition.

We estimate that within our regulated energy segment, approximately 88% of our electric revenues are regulated by the PSCW, 5% are regulated by the MPSC and the balance of our electric revenues is regulated by FERC. All of our natural gas revenues are regulated by the PSCW. Our ability to obtain rate adjustments in the future is dependent upon regulatory action, and there can be no assurance that we will be able to obtain rate adjustments in the future that will allow us to recover our costs and expenses and to maintain our current authorized rates of return.

We believe we have obtained the necessary permits, approvals and certificates for our existing operations and that our respective businesses are conducted in accordance with applicable laws; however, the impact of any future revision or changes in interpretations of existing regulations or the adoption of new laws and regulations applicable to us cannot be predicted. Changes in regulation, interpretations of regulations or the imposition of additional regulations could influence our operating environment and may result in substantial compliance costs.

Factors beyond our control could adversely affect project costs and completion of the natural gas-fired and coal-fired generating units we are constructing as part of our PTF strategy.

Under our PTF strategy, we expect to meet a significant portion of our future generation needs through the construction of two 545 MW natural gas-fired generating units at PWGS and two 615 MW coal-fired generating units to be located adjacent to our existing Oak Creek Power Plant. PWGS 1 was placed in service in July 2005 and has a current dependable capability of 575 MW. PWGS 2 is expected to go into service in the second quarter of 2008. OC 1 and OC 2 are scheduled to go into service in 2009 and 2010, respectively.

Large construction projects of this type are subject to usual construction risks over which we will have limited or no control and which might adversely affect project costs and completion time. These risks include, but are not limited to, shortages of, the inability to obtain or the cost of labor or materials, the inability of the general contractor or subcontractors to perform under their contracts, strikes, adverse weather conditions, the inability to obtain necessary permits in a timely manner, legal challenges and appeals to granted permits, including the WPDES permit granted in connection with the Oak Creek expansion, changes in applicable law or regulations, adverse interpretation or enforcement of permit conditions, laws and regulations by courts or the permitting agencies, other governmental actions and events in the global economy.

If final costs for the construction of the PWGS units exceed the fixed costs allowed in the PSCW order, absent a finding by the PSCW of extraordinary circumstances, such as force majeure conditions, this excess will not adjust the amount of the lease payments to be recovered from Wisconsin Electric's ratepayers. If final costs of the Oak Creek expansion are within 5% of the targeted cost, and the additional costs are deemed prudent by the PSCW, the final lease payments for the Oak Creek expansion to be recovered from Wisconsin Electric's ratepayers would be adjusted to reflect the actual construction costs. Costs above the 5% cap would not be included in lease payments or recovered from customers absent a finding by the PSCW of extraordinary circumstances, such as force majeure conditions.

We face significant costs of compliance with existing and future environmental regulations.

We are subject to extensive environmental regulations affecting our past, present and future operations relating to, among other things, air emissions such as $CO_{2,}$ SO_2, $NO_{x,}$ small particulates and mercury; water discharges; management of hazardous and solid waste (including polychlorinated biphenyls (PCBs)); and removal of degraded lead paint. We incur significant expenditures in complying with these environmental requirements, including expenditures for the installation of pollution control equipment, environmental monitoring, emissions fees and permits at all of our facilities.

Existing environmental regulations may be revised or new laws or regulations may be adopted which could result in significant additional expenditures, operating restrictions on our facilities and increased compliance costs. In addition to requiring capital expenditures, the operation of emission control equipment to meet emission limits and further regulations on our intake and discharge of water could increase our operating costs and could reduce the generating capacity of our power plants. In the event we are not able to recover all of our environmental expenditures from our customers in the future, our results of operations could be adversely affected.

Our electric and gas utility businesses are also subject to significant liabilities related to the investigation and remediation of environmental contamination at our current and former facilities, as well as at third-party owned sites. Due to the potential for imposition of stricter standards and greater regulation in the future and the possibility that other potentially responsible parties may not be financially able to contribute to cleanup costs, conditions may change or additional contamination may be discovered, our remediation costs could increase, and the timing of our capital and/or operating expenditures in the future may accelerate.

In addition, we may also be responsible for liabilities associated with the environmental condition of the facilities that we have previously owned and operated, regardless of whether the liabilities arose before, during or after the time we owned or operated the facilities. If we fail to comply with environmental laws and regulations or cause harm to the environment or persons, even if caused by factors beyond our control, that failure or harm may result in the assessment of civil or criminal penalties and damages against us. The incurrence of a material environmental liability could have a significant adverse effect on our results of operations and financial condition.

We may face significant costs to comply with the regulation of greenhouse gas emissions.

Global warming is increasingly a concern for the energy industry. Although there continues to be significant debate regarding the extent of global warming and the impact of human activity, federal and state legislative proposals have been introduced to regulate the emission of greenhouse gases, particularly CO_2. In addition, there have been international efforts seeking legally binding reductions in emissions of greenhouse gases.

We believe it is likely that future governmental legislation and/or regulation may require us either to limit greenhouse gas emissions from our operations or to purchase allowances for such emissions. However, we cannot predict what form these future regulations will take, the stringency of the regulations or when they will become effective. Several bills have been introduced in the United States Congress that would compel CO_2 emission reductions. While none have yet been passed by Congress, the competing bills remain pending. Proposals under consideration include limitations on the amount of greenhouse gases that can be emitted (so called "caps") together with systems of trading permitted emissions capacities. This type of system could require us to reduce emissions, even though the technology is not currently available for efficient reduction, or to purchase costly allowances for such emissions. Emissions also could be taxed independently of limits.

In April 2007, the United States Supreme Court concluded that the EPA already has authority to regulate CO_2 emissions under the CAA. As a result, the EPA is now reconsidering whether to regulate motor vehicle emissions of CO_2 under the CAA. Any decision to regulate motor vehicle CO_2 emissions under the CAA may have significant implications for stationary sources of CO_2 emissions including fossil fuel fired electric generating plants.

At the state level, on April 5, 2007, the Governor of Wisconsin signed Executive Order 191 creating the Task Force on Global Warming to bring together a group of Wisconsin business, industry, government, energy and environmental leaders to examine the effects of, and solutions to, global warming in Wisconsin. We are actively participating in the Task Force. The purpose of the Task Force is to discuss and analyze possible solutions to global warming challenges that pose a threat to Wisconsin's economic and environmental health. The Task Force is

charged with creating a state plan of action to deliver to the Governor to reduce greenhouse gas emissions in Wisconsin. The work of the Governor's Task Force is ongoing.

In addition, on November 14, 2007, the Governor of Michigan signed Executive Order 2007-42 creating the Michigan Climate Action Council, which is similar in scope and purpose to the Task Force on Global Warming in Wisconsin.

The Governors of both Michigan and Wisconsin have signed on to the "Midwestern Greenhouse Gas Reduction Accord" and the associated "platform" document developed through the Midwest Governor's Association. The stated goal of the platform is to "maximize the energy resources and economic advantages and opportunities of Midwestern states while reducing emissions of atmospheric CO_2 and other greenhouse gases". Certain elements of this agreement have the potential to impact the cost and nature of our operations in Wisconsin and Michigan.

These state and regional initiatives could lead to legislation and regulation of greenhouse gas emissions that could be implemented sooner and/or independent of federal regulation. These regulations could be more stringent than any federal legislation that is adopted.

There is no guarantee that we will be allowed to fully recover costs incurred to comply with any future legislation and/or regulation that requires a reduction in greenhouse gas emissions, or that recovery will not be delayed or otherwise conditioned. Future legislation and/or regulation designed to reduce greenhouse gas emissions could make some of our electric generating units uneconomic to maintain or operate and could affect future results of operations, cash flows and possibly financial condition if such costs are not recovered through regulated rates.

We continue to monitor the legislative and regulatory developments in this area. Although we expect the regulation of greenhouse gas emissions to have a material impact on our operations and rates, we believe it is premature to attempt to quantify the possible costs of the impacts.

Our business is dependent on our ability to successfully access capital markets.

We rely on access to short-term and long-term capital markets to support our capital expenditures and other capital requirements, including expenditures for our utility infrastructure and to comply with future regulatory requirements. We have historically secured funds from a variety of sources, including the issuance of short-term and long-term debt securities, preferred stock and common stock. Recently, certain investment banks announced the adoption of the "Carbon Principles," a set of guidelines designed to help the investment banks assess environmental risk in connection with the financing of new fossil fuel power plants. The Carbon Principles are expected to be employed in conjunction with an "Enhanced Environmental Diligence Process" in evaluating whether to participate in the financing of such projects.

Successful implementation of our long-term business strategies is dependent upon our ability to access the capital markets under competitive terms and rates. If our access to the capital markets were limited due to a rating downgrade, prevailing market conditions or other factors, our results of operations and financial condition could be materially and adversely affected.

Acts of terrorism could materially and adversely affect our financial condition and results of operations.

Our electric generation and gas transportation facilities, including the facilities of third parties on which we rely, could be targets of terrorist activities, including cyber terrorism. A terrorist attack on our facilities (or those of third parties) could result in a full or partial disruption of our ability to generate, transmit, transport, purchase or distribute electricity or natural gas or cause environmental repercussions. Any operational disruption or environmental repercussions could result in a significant decrease in our revenues or significant reconstruction or remediation costs, which could materially and adversely affect our results of operations and financial condition.

Energy sales are impacted by seasonal factors and varying weather conditions from year-to-year.

Our electric and gas utility businesses are generally seasonal businesses. Demand for electricity is greater in the summer and winter months associated with cooling and heating. In addition, demand for natural gas peaks in the winter heating season. As a result, our overall results in the future may fluctuate substantially on a seasonal basis. In addition, we have historically had lower revenues and net income when weather conditions are milder.

Our rates in Wisconsin are set by the PSCW based on estimated temperatures which approximate 20-year averages. Mild temperatures during the summer cooling season and during the winter heating season will negatively impact the results of operations and cash flows of our electric utility business. In addition, mild temperatures during the winter heating season negatively impact the results of operations and cash flows of our gas utility business.

Higher natural gas costs may negatively impact our electric and gas utility operations.

Significant increases in the cost of natural gas affect our electric and gas utility operations. Natural gas costs have increased in recent years because the supply of natural gas has not kept pace with the demand for natural gas, which has grown throughout the United States as a result of increased reliance on natural gas-fired electric generating facilities. We expect that demand for natural gas will remain high into the foreseeable future and that significant price relief will not occur until additional natural gas reserves are developed.

Wisconsin Electric burns natural gas in several of its peaking power plants and in the leased PWGS 1 and as a supplemental fuel at several coal-fired plants. In many instances the cost of purchased power is tied to the cost of natural gas. In addition, higher natural gas costs also can have the effect of increasing demand for other sources of fuel thereby increasing the costs of those fuels as well. Wisconsin Electric bears the regulatory risk for the recovery of fuel and purchased power costs when those costs are higher than the base rate established in its rate structure. For 2008, Wisconsin Electric will be unable to prospectively recover fuel and purchased power costs until the costs exceed a pre-established annual band.

In addition, higher natural gas costs increase our working capital requirements. As a result of GCRMs, our gas distribution business receives dollar for dollar pass through of the cost of natural gas. However, increased natural gas costs increase the risk that customers will switch to alternative sources of fuel or reduce their usage, which could reduce future gas margins. In addition, higher natural gas costs combined with slower economic conditions also expose us to greater risks of accounts receivable write-offs as more customers are unable to pay their bills.

We may not be able to obtain an adequate supply of coal, which could limit our ability to operate our coal-fired facilities.

We are dependent on coal for much of our electric generating capacity. While we have coal supply and transportation contracts in place, there can be no assurance that the counterparties to these agreements will fulfill their obligations to supply coal to us. The suppliers under these agreements may experience financial or operational problems that inhibit their ability to fulfill their obligations to us. In addition, suppliers under these agreements may not be required to supply coal to us under certain circumstances, such as in the event of a natural disaster. If we are unable to obtain our coal requirements under our coal supply and transportation contracts, we may be required to purchase coal at higher prices, or we may be forced to obtain additional power purchases through other potentially higher cost generating resources in the MISO Energy Markets. Higher costs to obtain coal increase our working capital requirements.

Our financial performance may be adversely affected if we are unable to successfully operate our facilities.

Our financial performance depends on the successful operation of our electric generating and gas distribution facilities. Operation of these facilities involves many risks, including: operator error and breakdown or failure of equipment processes; fuel supply interruptions; labor disputes; operating limitations that may be imposed by environmental or other regulatory requirements; or catastrophic events such as fires, earthquakes, explosions, floods or other similar occurrences. Unplanned outages can result in additional maintenance expenses as well as incremental replacement power costs.

Poor investment performance of pension plan holdings and other factors impacting pension plan costs could unfavorably impact our liquidity and results of operations.

Our cost of providing non-contributory defined benefit pension plans are dependent upon a number of factors resulting from actual plan experience and assumptions concerning the future, such as earnings on plan assets, discount rates, the level of interest rates used to measure the required minimum funding levels of the plans, future government regulation and our required or voluntary contributions to be made to the plans. Changes made to the plans may also impact current and future pensions costs. We expect to contribute approximately $45.4 million to fund the pension plans in 2008. Depending upon the growth rate of the pension investments over time and depending upon the other factors impacting our costs as listed above, we could be required to contribute significant additional amounts in the future to fund our plans. These additional funding obligations could have a material adverse impact on our cash flows, financial condition or results of operations.

We are exposed to risks related to general economic conditions in our service territories.

Our electric and gas utility businesses are impacted by the economic cycles of the customers we serve. In the event regional economic conditions or the demand for products produced in our service area decline, we may experience reduced demand for electricity and/or natural gas that could result in decreased earnings and cash flow. In addition, regional economic conditions also impact our collections of accounts receivable.

Customer growth in our service areas affects our results of operations.

Our results of operations are affected by customer growth in our service areas. Customer growth can be affected by population growth as well as economic factors in Wisconsin and the Upper Peninsula of Michigan, including job and income growth. Customer growth directly influences the demand for electricity and gas, and the need for additional power generation and generating facilities. A population decline in our service territories or slower than anticipated customer growth could have a material adverse impact on our cash flow, financial condition or results of operations.

We are a holding company and are subject to restrictions on our ability to pay dividends.

Wisconsin Energy is a holding company and has no significant operations of its own. Accordingly, our ability to meet our financial obligations and pay dividends on our common stock is dependent upon the ability of our subsidiaries to pay amounts to us, whether through dividends or other payments. The ability of our subsidiaries to pay amounts to us will depend on the earnings, cash flows, capital requirements and general financial condition of our subsidiaries and on regulatory limitations. Our subsidiaries have dividend payment restrictions based on the terms of their outstanding preferred stock and regulatory limitations applicable to them. In addition, each of Wisconsin Energy, Wisconsin Electric and Wisconsin Gas bank back-up credit facilities have specified total funded debt to capitalization ratios that must be maintained.

Provisions of the Wisconsin Utility Holding Company Act limit our ability to invest in non-utility businesses and could deter takeover attempts by a potential purchaser of our common stock that would be willing to pay a premium for our common stock.

Under the Wisconsin Utility Holding Company Act, we remain subject to certain restrictions that have the potential of limiting our diversification into non-utility businesses. Under the public utility holding company law, the sum of certain assets of all non-utility affiliates in a holding company system may not exceed 25% of the assets of all public utility affiliates.

In addition, this act precludes the acquisition of 10% or more of the voting shares of a holding company of a Wisconsin public utility unless the PSCW has first determined that the acquisition is in the best interests of utility customers, investors and the public. This provision and other requirements of this act may delay or reduce the likelihood of a sale or change of control of Wisconsin Energy. As a result, shareholders may be deprived of opportunities to sell some or all of their shares of our common stock at prices that represent a premium over market prices.

Governmental agencies could modify our permits, authorizations or licenses.

Wisconsin Electric, Wisconsin Gas and Edison Sault are required to comply with the terms of various permits, authorizations and licenses. These permits, authorizations and licenses may be revoked or modified by the agencies that granted them if facts develop that differ significantly from the facts assumed when they were issued. In addition, discharge permits and other approvals and licenses are often granted for a term that is less than the expected life of the associated facility. Licenses and permits may require periodic renewal, which may result in additional requirements being imposed by the granting agency.

Also, if we are unable to obtain, renew or comply with these governmental permits, authorizations or licenses, or if we are unable to recover any increased costs of complying with additional license requirements or any other

associated costs in our rates in a timely manner, our results of operations and financial condition could be materially and adversely affected.

Restructuring in the regulated energy industry could have a negative impact on our business.

The regulated energy industry continues to experience significant structural changes. Increased competition in the retail and wholesale markets, which may result from restructuring efforts, could have a significant adverse financial impact on us. It is uncertain when retail access might be implemented in Wisconsin; however, Michigan has adopted retail choice which potentially affects our Michigan operations. Under retail access legislation, customers are permitted to choose their own electric generation supplier. All Michigan electric customers were able to choose their electric generation supplier beginning in January 2002. Although competition and customer switching to alternative suppliers in our service territories in Michigan has been limited, the additional competitive pressures resulting from retail access could lead to a loss of customers and our incurring stranded costs.

FERC continues to support the existing RTOs that affect the structure of the wholesale market within those RTOs. In connection with its status as a FERC approved RTO, MISO implemented the MISO Energy Markets on April 1, 2005. The MISO Energy Markets rules require that all market participants submit day-ahead and/or real-time bids and offers for energy at locations across the MISO region. MISO then calculates the most efficient solution for all of the bids and offers made into the market that day and establishes a LMP that reflects the market price for energy. As a participant in the MISO Energy Markets, we are required to follow MISO's instructions when dispatching generating units to support MISO's responsibility for maintaining stability of the transmission system. In addition, MISO plans to implement an Ancillary Services Market for operating reserves that would be simultaneously co-optimized with MISO's existing energy markets. The Ancillary Services Market is expected to commence in June 2008. The implementation of these and other new market designs has the potential to increase costs of transmission, costs associated with inefficient generation dispatching, costs of participation in the market and costs associated with estimated payment settlements.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

We own our principal properties outright, except that the major portion of our electric utility distribution lines, steam utility distribution mains and gas utility distribution mains and services are located, for the most part, on or under streets and highways and on land owned by others and are generally subject to granted easements, consents or permits.

As of December 31, 2007, we owned the following generating stations with dependable capabilities during 2007 as indicated:

Name	Fuel	No. of Generating Units	Dependable Capability in MW (a) July
Coal-Fired Plants			
Oak Creek	Coal	4	1,135
Presque Isle	Coal	7	547
Pleasant Prairie	Coal	2	1,208
Valley	Coal	2	267
Edgewater 5 (b)	Coal	1	105
Milwaukee County	Coal	3	10
Total Coal-Fired Plants		19	3,272
Hydro Plants (14 in number)		107	81
Port Washington Generating Station (c)	Gas	1	575
Germantown Combustion Turbines	Gas/Oil	5	345
Concord Combustion Turbines	Gas/Oil	4	388
Paris Combustion Turbines	Gas/Oil	4	400
Byron Wind Turbines (d)	Wind	2	-
Other Combustion Turbines & Diesel	Gas/Oil	5	28
Total System		147	5,089

(a) Dependable capability is the net power output under average operating conditions with equipment in an average state of repair as of a given month in a given year. We are a summer peaking electric utility. The values were established by test and may change slightly from year to year.

(b) We have a 25% interest in Edgewater 5 Generating Unit, which is operated by Alliant Energy Corp, an unaffiliated utility.

(c) Effective July 2005, Wisconsin Electric began leasing PWGS 1, a natural gas-fired generation unit with 575 MW of dependable capability, from We Power under a 25 year lease.

(d) The Byron Wind Turbines are able to generate up to 1.2 MW of electricity; however, due to the intermittent characteristics of wind power, their dependable capability is less than 1 MW.

As of December 31, 2007, we operated approximately 22,140 pole-miles of overhead distribution lines and 22,910 miles of underground distribution cable, as well as approximately 358 distribution substations and 280,750 line transformers. We own various office buildings and service centers throughout our electric utility service areas.

As of December 31, 2007, our gas distribution system included approximately 20,042 miles of distribution and transmission mains connected at 184 gate stations to the pipeline transmission systems of ANR Pipeline Company, Guardian, Natural Gas Pipeline Company of America, Northern Natural Pipeline Company, Great Lakes Transmission Company, Viking Gas Transmission and Michigan Consolidated Gas Company. We have liquefied natural gas storage plants which convert and store, in liquefied form, natural gas received during periods of low

consumption. The liquefied natural gas storage plants have a send-out capability of 73,600 Dth per day. We also have propane air systems for peaking purposes. These propane air systems will provide approximately 2,400 Dth per day of supply to the system. Our gas distribution system consists almost entirely of plastic and coated steel pipe.We also own office buildings, gas regulating and metering stations and major service centers, including garage and warehouse facilities, in certain communities in which we serve. Where distribution lines and services and gas distribution mains and services occupy private property, we have in some, but not all instances, obtained consents, permits or easements for these installations from the apparent owners or those in possession of those properties, generally without an examination of ownership records or title.

As of December 31, 2007, the combined steam systems supplied by the Valley and Milwaukee County Power Plants consisted of approximately 43 miles of both high pressure and low pressure steam piping, 9 miles of walkable tunnels and other pressure regulating equipment.

We Power:

We Power completed construction of the first natural gas unit, PWGS 1, in July 2005. PWGS 1 has a current dependable capability of 575 MW. Construction of a second 545 MW natural gas unit at PWGS has begun, and we expect the unit to be placed into service in the second quarter of 2008. We Power also received authorization from the PSCW to build two 615 MW coal plants (of which we will own approximately a 515 MW share of each unit) adjacent to the site of Wisconsin Electric's existing Oak Creek Power Plant. Construction commenced at this site in June 2005. For information about PTF, see Factors Affecting Results, Liquidity and Capital Resources -- Power the Future in Item 7.

Wisvest LLC:

Wisvest owns a chilled water production and distribution facility located in Milwaukee County, Wisconsin.

Wispark LLC:

As of December 31, 2007, Wispark properties, owned in full or through minority interests in joint ventures, included the following commercial and industrial parks in the State of Wisconsin: LakeView Corporate Park located near Kenosha, Wisconsin and GrandView Business Park in Racine, Wisconsin. Wispark developed Gaslight Pointe, a residential and commercial complex located in Racine. Wispark owns other properties located in Wisconsin Electric's service territories that are held for future development or sale. Wispark is a minority owner in an industrial park located in Gurnee, Illinois.

Minergy LLC:

Minergy owns a GlassPack ® facility in Winneconne, Wisconsin.

ITEM 3. LEGAL PROCEEDINGS

In addition to those legal proceedings discussed below, we are currently, and from time to time, subject to claims and suits arising in the ordinary course of business. Although the results of these other legal proceedings cannot be predicted with certainty, management believes, after consultation with legal counsel, that the ultimate resolution of these proceedings will not have a material adverse effect on our financial statements.

ENVIRONMENTAL MATTERS

We are subject to federal, state and certain local laws and regulations governing the environmental aspects of our operations. Management believes that, perhaps with immaterial exceptions, our existing facilities are in compliance with applicable environmental requirements.

EPA Information Requests:

Wisconsin Electric and Wisconsin Gas responded to an EPA request received in August 2004, for information pursuant to CERCLA Section 104(e) for the Solvay Coke and Gas Site located in Milwaukee, Wisconsin. All potentially responsive records and corporate legal files have been reviewed and responsive information was provided in October 2004. A predecessor company of Wisconsin Electric owned a parcel of property that is within the property boundaries of the site. A predecessor company of Wisconsin Gas had a customer and corporate relationship with the entity that owned and operated the site, Milwaukee Solvay Coke Company. In July 2005, Wisconsin Gas received a general notice letter from the EPA identifying Wisconsin Gas as a potentially responsible party under CERCLA. In April 2006, we received a special notice letter from the EPA

identifying both Wisconsin Gas and Wisconsin Electric as potentially responsible parties and commencing a negotiation period with the EPA and other parties regarding the conduct of a RI/FS and reimbursement of the EPA's costs. Wisconsin Electric and Wisconsin Gas, along with other parties, have entered into an Administrative Settlement Agreement and Order with the EPA to perform the RI/FS and reimburse the EPA's oversight costs. The parties anticipate that investigation activities will commence in 2008. Under the Settlement Agreement, neither Wisconsin Electric nor Wisconsin Gas admits to any liability for the site, waives any liability defenses, or commits to perform future site remedial activities at this time. The companies' share of the costs to perform the RI/FS and reimburse the EPA's oversight costs, as well as potential future remediation cost estimates and reserves, are included in the estimated manufactured gas plant values reported in Note S -- Commitments and Contingencies in the Notes to Consolidated Financial Statements in Item 8.

See Environmental Compliance in Item 1 and Environmental Matters, Manufactured Gas Plant Sites, Ash Landfill Sites and EPA - Consent Decree in Note S -- Commitments and Contingencies in the Notes to Consolidated Financial Statements which are incorporated by reference herein, for a discussion of matters related to certain solid waste and coal-ash landfills, manufactured gas plant sites and air quality.

UTILITY RATE MATTERS

See Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters and Power the Future in Item 7 for information concerning rate matters in the jurisdictions where Wisconsin Electric, Wisconsin Gas and Edison Sault do business.

OTHER MATTERS

Used Nuclear Fuel Storage and Removal:

See Factors Affecting Results, Liquidity and Capital Resources -- Nuclear Operations in Item 7 for information concerning the DOE's breach of contract with Wisconsin Electric that required the DOE to begin permanently removing used nuclear fuel from Point Beach by January 31, 1998.

Stray Voltage:

In recent years, several actions by dairy farmers have been commenced or claims made against Wisconsin Electric for loss of milk production and other damages to livestock allegedly caused by stray voltage resulting from the operation of its electrical system.

In May 2005, a stray voltage lawsuit was filed against Wisconsin Electric. This lawsuit was settled in June 2007 and such settlement did not have a material adverse effect on our financial condition or results of operations.

Even though any claims which may be made against Wisconsin Electric with respect to stray voltage and ground currents are not expected to have a material adverse effect on its financial condition, we continue to evaluate various options and strategies to mitigate this risk. For additional information, see Factors Affecting Results, Liquidity and Capital Resources -- Legal Matters in Item 7.

For information regarding additional legal matters, see Factors Affecting Results, Liquidity and Capital Resources -- Legal Matters in Item 7.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

No matters were submitted to a vote of our security holders during the fourth quarter of 2007.

EXECUTIVE OFFICERS OF THE REGISTRANT

The names, ages at December 31, 2007 and positions of our executive officers are listed below along with their business experience during the past five years. All officers are appointed until they resign, die or are removed pursuant to the Bylaws. There are no family relationships among these officers, nor is there any agreement or understanding between any officer and any other person pursuant to which the officer was selected. Reference to Wisconsin Gas LLC includes the time spent with the company prior to its conversion from a corporation to an LLC.

Gale E. Klappa.

Age 57.

- Wisconsin Energy Corporation -- Chairman of the Board and Chief Executive Officer since May 2004. President since April 2003.
- Wisconsin Electric Power Company -- Chairman of the Board since May 2004. President and Chief Executive Officer since August 2003.
- Wisconsin Gas LLC -- Chairman of the Board since May 2004. President and Chief Executive Officer since August 2003.
- The Southern Company -- Executive Vice President, Chief Financial Officer and Treasurer from March 2001 to April 2003. Chief Strategic Officer from October 1999 to March 2001. The Southern Company is a public utility holding company serving the southeastern United States.
- Director of Joy Global, Inc.
- Director of Wisconsin Energy Corporation, Wisconsin Electric Power Company and Wisconsin Gas LLC since 2003.

Charles R. Cole. Age 61.

- Wisconsin Electric Power Company -- Senior Vice President since 2001.
- Wisconsin Gas LLC -- Senior Vice President since July 2004.

Stephen P. Dickson.

Age 47.

- Wisconsin Energy Corporation -- Vice President since 2005. Controller since 2000.
- Wisconsin Electric Power Company -- Vice President since 2005. Controller since 2000.
- Wisconsin Gas LLC -- Vice President since 2005. Controller since 1998.

James C. Fleming.

Age 62.

- Wisconsin Energy Corporation -- General Counsel since March 2006. Executive Vice President since January 2006.
- Wisconsin Electric Power Company -- General Counsel since March 2006. Executive Vice President since January 2006.
- Wisconsin Gas LLC -- General Counsel since March 2006. Executive Vice President since January 2006.
- Southern Company Services, Inc. -- Vice President and Associate General Counsel from 1998 to December 2005. Southern Company Services is an affiliate of The Southern Company, a public utility holding company serving the southeastern United States.

Frederick D. Kuester.

Age 57.

- Wisconsin Energy Corporation -- Executive Vice President since May 2004.
- Wisconsin Electric Power Company -- Executive Vice President since May 2004. Chief Operating Officer since October 2003.
- Wisconsin Gas LLC -- Executive Vice President since May 2004.
- Mirant Corporation -- Senior Vice President - International from 2001 to October 2003 and Chief Executive Officer of Mirant Asia-Pacific Limited from 1999 to October 2003. Mirant is a multi-national energy company that produces and sells electricity. Mirant Corporation and certain of its subsidiaries voluntarily filed for bankruptcy in July 2003. Other than certain Canadian subsidiaries, none of Mirant's international subsidiaries filed for bankruptcy.

Allen L. Leverett.

Age 41.

- Wisconsin Energy Corporation -- Executive Vice President since May 2004. Chief Financial Officer since July 2003.
- Wisconsin Electric Power Company -- Executive Vice President since May 2004. Chief Financial Officer since July 2003.
- Wisconsin Gas LLC -- Executive Vice President since May 2004. Chief Financial Officer since July 2003.
- Georgia Power Company -- Executive Vice President, Chief Financial Officer and Treasurer from May 2002 to July 2003. Assistant Treasurer from 2000 to 2002. Georgia Power Company is a utility affiliate of The Southern Company, a public utility holding company serving the southeastern United States.

Kristine Rappé.

Age 51.

- Wisconsin Energy Corporation -- Senior Vice President and Chief Adminmistrative Officer since May 2004. Corporate Secretary from 2001 to August 2004.
- Wisconsin Electric Power Company -- Senior Vice President and Chief Administrative Officer since May 2004. Corporate Secretary from 2001 to August 2004. Vice President from 1994 to April 2004.
- Wisconsin Gas LLC -- Senior Vice President and Chief Administrative Officer since May 2004. Corporate Secretary from 2001 to August 2004. Vice President from 2001 to April 2004.

Certain executive officers also hold offices in our non-utility subsidiaries.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

NUMBER OF COMMON STOCKHOLDERS

As of December 31, 2007, based upon the number of Wisconsin Energy Corporation stockholder accounts (including accounts in our dividend reinvestment and stock purchase plan), we had approximately 51,000 registered stockholders.

COMMON STOCK LISTING AND TRADING

Our common stock is listed on the New York Stock Exchange under the ticker symbol "WEC." Daily trading prices and volume can be found in the "NYSE Composite" section of most major newspapers, usually abbreviated as WI Engy.

DIVIDENDS AND COMMON STOCK PRICES

Common Stock Dividends of Wisconsin Energy:

Cash dividends on our common stock, as declared by the Board of Directors, are normally paid on or about the first day of March, June, September and December of each year. We review our dividend policy on a regular basis. Subject to any regulatory restrictions or other limitations on the payment of dividends, future dividends will be at the discretion of the Board of Directors and will depend upon, among other factors, earnings, financial condition and other requirements. For information regarding restrictions on the ability of our subsidiaries to pay us dividends, see Note J -- Common Equity in the Notes to Consolidated Financial Statements in Item 8.

On January 17, 2008, our Board of Directors announced that it increased our common stock quarterly dividend rate by 8.0%, to $0.27 per share. With the increase, the new dividend is equivalent to an annual rate of $1.08 per share. The Board has established a goal of increasing the annual dividend at a rate of approximately half of the expected rate of growth in earnings per share, subject to the factors referred to above.

Range of Wisconsin Energy Common Stock Prices and Dividends:

	2007			2006		
Quarter	High	Low	Dividend	High	Low	Dividend
First	$50.10	$45.67	$0.25	$42.35	$38.92	$0.23
Second	$50.00	$43.50	0.25	$40.91	$38.16	0.23
Third	$45.81	$41.06	0.25	$43.79	$39.75	0.23
Fourth	$50.48	$44.35	0.25	$48.70	$43.25	0.23

ISSUER PURCHASES OF EQUITY SECURITIES:

There were no purchases of our equity securities made by or on behalf of us or any affiliated purchaser (as defined in Exchange Act Rule 10b-18) during the three month period ended December 31, 2007. We do not report shares purchased by independent agents to satisfy obligations under our employee benefit plans and stock purchase and dividend reinvestment plan under this Item.

ITEM 6. SELECTED FINANCIAL DATA

WISCONSIN ENERGY CORPORATION

CONSOLIDATED SELECTED FINANCIAL AND STATISTICAL DATA

Financial	2007	2006	2005	2004	2003
Year Ended December 31					
Net income - Continuing Operations (Millions)	$ 336.5	$ 312.5	$ 303.6	$ 219.6	$ 201.3
Earnings per share - Continuing Operations					
Basic	$ 2.88	$ 2.67	$ 2.59	$ 1.87	$ 1.72
Diluted	$ 2.84	$ 2.64	$ 2.56	$ 1.84	$ 1.70
Dividends per share of common stock	$ 1.00	$ 0.92	$ 0.88	$ 0.83	$ 0.80
Common Stock Price - High During Year	$ 50.48	$ 48.70	$ 40.83	$ 34.60	$ 33.68
Common Stock Price - Low During Year	$ 41.06	$ 38.16	$ 33.35	$ 29.50	$ 22.56
Operating revenues (Millions)					
Utility energy	$ 4,224.8	$ 3,979.0	$ 3,793.0	$ 3,375.4	$ 3,263.9
Non-utility energy	75.7	69.1	40.0	19.9	12.3
Other including eliminations	(62.7)	(51.7)	(17.5)	10.8	5.9
Total operating revenues	$ 4,237.8	$ 3,996.4	$ 3,815.5	$ 3,406.1	$ 3,282.1
At December 31 (Millions)					
Total assets	$ 11,720.3	$ 11,130.2	$ 10,462.0	$ 9,565.4	$ 10,014.5
Long-term debt (including current maturities) and capital lease obligations	$ 3,525.3	$ 3,370.1	$ 3,527.0	$ 3,340.5	$ 3,736.7

CONSOLIDATED SELECTED QUARTERLY FINANCIAL DATA (Unaudited)

	(Millions of Dollars, Except Per Share Amounts) (a)	
	March	June

Three Months Ended	2007	2006	2007	2006
Operating revenues	$ 1,301.1	$ 1,247.0	$ 906.5	$ 814.4
Operating income	184.5	191.6	105.1	107.1
Income from Continuing Operations	101.1	104.4	57.7	59.7
Income (loss) from Discontinued Operations	(0.2)	1.3	(0.2)	3.2
Total Net Income	$ 100.9	$ 105.7	$ 57.5	$ 62.9
Earnings per share of common stock (basic) (b)				
Continuing operations	$ 0.86	$ 0.89	$ 0.49	$ 0.51
Discontinued operations	-	0.01	-	0.03
Total earnings per share (basic)	$ 0.86	$ 0.90	$ 0.49	$ 0.54
Earnings per share of common stock (diluted) (b)				
Continuing operations	$ 0.85	$ 0.88	$ 0.49	$ 0.50
Discontinued operations	-	0.01	-	0.03
Total earnings per share (diluted)	$ 0.85	$ 0.89	$ 0.49	$ 0.53

	September		December	
Three Months Ended	2007	2006	2007	2006
Operating revenues	$ 881.5	$ 839.8	$ 1,148.7	$ 1,095.2
Operating income	153.1	131.2	185.8	138.6
Income from Continuing Operations	83.1	70.8	94.6	77.6
Income (loss) from Discontinued Operations	(0.2)	-	(0.3)	(0.6)
Total Net Income	$ 82.9	$ 70.8	$ 94.3	$ 77.0
Earnings per share of common stock (basic) (b)				
Continuing operations	$ 0.71	$ 0.61	$ 0.81	$ 0.66
Discontinued operations	-	-	-	-
Total earnings per share (basic)	$ 0.71	$ 0.61	$ 0.81	$ 0.66
Earnings per share of common stock (diluted) (b)				
Continuing operations	$ 0.70	$ 0.60	$ 0.80	$ 0.65
Discontinued operations	-	-	-	-
	$ 0.70	$ 0.60	$ 0.80	$ 0.65

Total earnings per share (diluted)				

(a) Quarterly results of operations are not directly comparable because of seasonal and other factors. See Management's Discussion and Analysis of Financial Condition and Results of Operations.

(b) Quarterly earnings per share may not total to the amounts reported for the year since the computation is based on the weighted average common shares outstanding during each quarter.

ITEM 7.MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

CORPORATE DEVELOPMENTS

INTRODUCTION

Wisconsin Energy Corporation is a diversified holding company with subsidiaries primarily in a utility energy segment and a non-utility energy segment. Unless qualified by their context, when used in this document the terms Wisconsin Energy, the Company, our, us or we refer to the holding company and all of our subsidiaries.

Our utility energy segment, consisting of Wisconsin Electric and Wisconsin Gas, both doing business under the trade name of "We Energies", and Edison Sault, is engaged primarily in the business of generating electricity and distributing electricity and natural gas in Wisconsin and the Upper Peninsula of Michigan. Our non-utility energy segment primarily consists of We Power. We Power is principally engaged in the engineering, construction and development of electric power generating facilities for long-term lease to Wisconsin Electric.

CORPORATE STRATEGY

Business Opportunities

We seek to increase stockholder value by leveraging on our core competencies. Our key corporate strategy, announced in September 2000, is PTF. This strategy is designed to address Wisconsin's growing electric supply needs by increasing the electric generating capacity in the state while maintaining a fuel-diverse, reasonably priced electric supply. It is also designed to improve the delivery of energy within our distribution systems to meet increasing customer demands and to support our commitment to improved environmental performance. Our PTF strategy, which is discussed further below, is having and is expected to continue to have, a significant impact on our utility and non-utility energy segments. In July 2005, the first of four new electric generating units under our PTF strategy was placed into service. Construction on the remaining three units is underway with the second PWGS unit expected to be placed in service during the second quarter of 2008. Since 2000, we have been selling our non-core assets to direct more attention to the utility business and to finance PTF while reducing our debt leverage.

Sale of Point Beach:

On September 28, 2007, Wisconsin Electric sold Point Beach to an affiliate of FPL for approximately $924 million. Pursuant to the terms of the sale agreement, the buyer purchased Point Beach, its nuclear fuel, associated inventories and assumed the obligation to decommission the plant. Wisconsin Electric retained approximately $506 million of the sales proceeds, which represents the net book value of the assets sold and certain transaction costs. In addition, Wisconsin Electric has deferred the net gain on the sale of approximately $418 million as a regulatory liability and has deposited those proceeds into a restricted cash account.

In connection with the sale, Wisconsin Electric also transferred $390 million of decommissioning funds to the buyer. Wisconsin Electric then liquidated the balance of the decommissioning trust assets and retained approximately $552 million, which was also placed into the restricted cash account. We intend to use the cash in the restricted cash account and the interest earned on the balance, for the benefit of our customers and to pay certain taxes related to the liquidation of the qualified decommissioning trust. Our regulators are directing the manner in which these proceeds will benefit customers. For further information on the 2008 rate case, see Utility Rates and Regulatory Matters under Factors Affecting Results, Liquidity and Capital Resources in this report.

A long-term power purchase agreement with the buyer became effective upon closing of the sale. Pursuant to this agreement, Wisconsin Electric is purchasing all of the energy produced by Point Beach. The power purchase agreement extends through 2030 for Unit 1 and 2033 for Unit 2. Based on the agreement, we will be paying a pre-determined price per MWh for energy delivered. For additional information on the sale of Point Beach, see Nuclear Operations under Factors Affecting Results, Liquidity and Capital Resources in this report.

Utility Energy Segment:

Our utility energy segment strives to provide reasonably priced energy delivered at high levels of customer service and reliability. We expect our prices to be established by our regulatory bodies under traditional rate based, cost of service methodologies. We continue to gain efficiencies and improve the effectiveness

of our service deliveries through the combined support operations of our electric and gas businesses. We work to obtain a reliable, reasonably-priced supply of electricity through plants that we operate and various long-term supply contracts.

Non-Utility Energy Segment:

Our primary focus in this segment is to improve the supply of electric generation in Wisconsin. We Power was formed to design, construct, own and lease new generation assets under our PTF strategy.

Power the Future Strategy:

In February 2001, we filed a petition with the PSCW that would allow us to begin implementing our 10-year PTF strategy to improve the supply and reliability of electricity in Wisconsin. PTF is intended to meet a growing demand for electricity and ensure a diverse fuel mix while keeping electricity prices reasonable. Under PTF, we are (1) investing approximately $2.6 billion in 2,120 MW of new natural gas-fired and coal-fired generating capacity at existing sites; (2) upgrading our existing electric generating facilities; and (3) investing in upgrades of our existing energy distribution system.

Subsequent to our February 2001 filing, the Wisconsin legislature amended several laws, making changes which were critical to the implementation of PTF. In October 2001, the PSCW issued a declaratory ruling finding, among other things, that it was prudent to proceed with PTF and for us to incur the associated pre-certification expenses. However, individual expenses are subject to review by the PSCW in order to be recovered.

In November 2001, we created We Power to design, construct, own and lease the new generating capacity. Wisconsin Electric will lease each new generating facility from We Power as well as operate and maintain the new plants under 25- to 30-year lease agreements approved by the PSCW. Based upon the structure of the leases, we expect to recover the investments in We Power's new facilities over the initial lease term. At the end of the leases, Wisconsin Electric will have the right to acquire the plants outright at market value or to renew the leases. Wisconsin Electric expects that payments under the plant leases will be recoverable in rates under the provisions of the Wisconsin Leased Generation Law.

Under our PTF strategy, we expect to meet a significant portion of our future generation needs through We Power's construction of the PWGS units and the Oak Creek expansion.

As of December 31, 2007, we:

- Received approval from the PSCW to build two 545 MW natural gas-fired intermediate load units in Port Washington, Wisconsin (PWGS 1 and PWGS 2). PWGS 1 was placed into service in July 2005 and is fully operational. PWGS 1 was completed within the PSCW approved cost parameters.
- Completed site preparation for PWGS 2 and procured all of the major components for PWGS 2. Construction is underway, and PWGS 2 is expected to become operational in the second quarter of 2008.
- Received approval from the PSCW to build two 615 MW coal-fired base load units (OC 1 and OC 2) adjacent to the site of our existing Oak Creek Power Plant in Oak Creek, Wisconsin (the Oak Creek expansion), with OC 1 expected to be in service in 2009 and OC 2 in 2010. The CPCN was granted contingent upon our obtaining the necessary environmental permits. We have received all permits necessary to commence construction. In June 2005, construction commenced at the site.
- Completed the planned sale of approximately a 17% ownership interest in the Oak Creek expansion to two co-owners.
- Received approval from the PSCW for various leases between We Power and Wisconsin Electric.

Through December 31, 2007, we have financed our PTF expenditures with internally generated cash, asset sales and debt financings. Future expenditures are expected to be financed with internally generated cash and debt financings. We currently do not plan to issue any new common equity as part of our PTF program.

Our primary risks under PTF are construction risks associated with the schedule and costs for both our Oak Creek expansion and PWGS 2; continuing legal challenges to permits obtained and changes in applicable laws or regulations; adverse interpretation or enforcement of permit conditions, laws and regulations by the permitting agencies; the inability to obtain necessary operating permits in a timely manner; obtaining the investment capital from outside sources necessary to implement the strategy; governmental actions; and events in the global economy.

For further information concerning PTF capital requirements, see Liquidity and Capital Resources below. For additional information regarding risks associated with the PTF strategy, as well as the regulatory process and specific regulatory approvals, see Factors Affecting Results, Liquidity and Capital Resources below.

Divestiture of Assets

Our PTF strategy led to a decision to divest non-core businesses. These non-core businesses primarily included non-utility generation assets located outside of Wisconsin and a substantial amount of Wispark's real estate portfolio, as well as our manufacturing business. In addition, in 2001 we contributed our transmission assets to ATC and received cash proceeds of $119.8 million and an economic interest in ATC. Finally, in 2006 we concluded that it was in the best interests of customers and stockholders to sell Point Beach. In 2007, we sold Point Beach for approximately $924 million. Since 2000, we have received total proceeds of approximately $3.1 billion from the divestiture of assets as follows:

Proceeds from divestitures:	2000 - 2007
(Millions of Dollars)	
Point Beach	$924.1
Manufacturing	857.0
Non-Utility Energy	616.8
Real Estate	482.9
Transmission	119.8
Guardian	38.5
Other	95.7
Total	$3,134.8

RESULTS OF OPERATIONS

CONSOLIDATED EARNINGS

The following table compares our operating income by business segment and our net income for 2007, 2006 and 2005:

Wisconsin Energy Corporation	2007	2006	2005
		(Millions of Dollars)	
Utility Energy	$586.0	$532.8	$542.4
Non-Utility Energy	47.4	43.1	19.5
Corporate and Other	(4.9)	(7.4)	1.0
Total Operating Income	628.5	568.5	562.9
Equity in Earnings of Transmission Affiliate	43.1	38.6	34.6
Other Income and Deductions, net	48.9	53.1	28.7
Interest Expense, net	167.6	172.7	173.4
Income From Continuing Operations Before Income Taxes	552.9	487.5	452.8
Income Taxes	216.4	175.0	149.2
Income From Continuing Operations	336.5	312.5	303.6
Income (Loss) From Discontinued Operations, Net of Tax	(0.9)	3.9	5.1
Net Income	$335.6	$316.4	$308.7
Diluted Earnings Per Share			
Continuing Operation	$2.84	$2.64	$2.56
Discontinued Operations	(0.01)	0.03	0.05
Total Diluted Earnings Per Share	$2.83	$2.67	$2.61

An analysis of contributions to operating income by segment and a more detailed analysis of results in 2007, 2006 and 2005 follow.

UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

2007 vs. 2006:

Our utility energy segment contributed $586.0 million of operating income during 2007 compared with $532.8 million of operating income during 2006. During 2007 we experienced more favorable weather which increased electric and gas sales. In addition, we experienced an increase in retail sales as a result of customer growth and we reached a settlement regarding a billing dispute with our largest customers, two iron ore mines. These items were partially offset by an increase in fuel and purchased power expenses.

2006 vs. 2005:

Our utility energy segment contributed $532.8 million of operating income during 2006 compared with $542.4 million of operating income during 2005. During 2006, we experienced mild weather, which reduced electric and gas sales. In addition, operation and maintenance expenses increased due to the timing of scheduled outages and maintenance projects at our coal units. However, these items were largely offset by improved recovery of fuel costs, only one scheduled refueling outage at Point Beach and increased gas margins.

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The following table summarizes our utility energy segment's operating income during 2007, 2006 and 2005:

Utility Energy Segment	2007	2006	2005
		(Millions of Dollars)	
Operating Revenues			
Electric	$2,705.7	$2,529.4	$2,349.7
Gas	1,481.2	1,419.9	1,417.5
Other	37.9	29.7	25.8
Total Operating Revenues	4,224.8	3,979.0	3,793.0
Fuel and Purchased Power	1,000.6	806.2	780.8
Cost of Gas Sold	1,052.7	1,018.3	1,047.3
Gross Margin	2,171.5	2,154.5	1,964.9
Other Operating Expenses			
Other Operation and Maintenance	1,174.2	1,211.1	1,010.4
Depreciation, Decommissioning			
and Amortization	315.2	314.0	324.1
Property and Revenue Taxes	102.6	96.6	88.0
Amortization of Gain	(6.5)	-	-
Operating Income	$586.0	$532.8	$542.4

During September 2007, we completed the sale of Point Beach. In connection with the sale, a power purchase agreement with an affiliate of FPL became effective to purchase all of the energy produced by Point Beach. As a result of the sale and the power purchase agreement, we expect future income statements to look different than historical income statements. Prospectively, we expect to see significantly higher purchased power expense because we will be purchasing energy from Point Beach. We also expect to see a reduction of other operation and maintenance costs, as well as lower depreciation, decommissioning and amortization costs because we no longer own Point Beach. Under the power purchase agreement, we also expect to see higher costs for purchased power in the summer months and lower amounts in the non-summer months. Finally, we expect our future income statements to reflect the regulatory impact of the amortization of the gain resulting from the sale of Point Beach.

Electric Utility Gross Margin

The following table compares our electric utility gross margin during 2007 with similar information for 2006 and 2005, including a summary of electric operating revenues and electric sales by customer class:

	Electric Revenues and Gross Margin			MWh Sales		
Electric Utility Operations	2007	2006	2005	2007	2006	2005
	(Millions of Dollars)			(Thousands, Except Degree Days)		
Customer Class						
Residential	$929.6	$883.2	$827.6	8,586.6	8,322.7	8,562.7
Small Commercial/Industrial	861.7	814.8	746.1	9,430.3	9,142.2	9,192.7
Large Commercial/Industrial	676.9	647.5	602.4	11,245.6	11,173.1	11,687.5
Other-Retail	19.7	19.3	17.9	168.7	169.9	171.7
Total Retail Sales	2,487.9	2,364.8	2,194.0	29,431.2	28,807.9	29,614.6
Wholesale - Other	95.1	78.0	94.7	2,178.5	2,057.6	2,541.9
Resale - Utilities	81.6	51.2	21.3	1,434.5	1,025.7	313.7
Other Operating Revenues	41.1	35.4	39.7	-	-	-
Total	$2,705.7	$2,529.4	$2,349.7	33,044.2	31,891.2	32,470.2
Fuel and Purchased Power						
Fuel	570.1	487.9	432.7			
Purchased Power	419.7	309.8	340.3			
Total Fuel and Purchased Power	989.8	797.7	773.0			
Total Electric Gross Margin	$1,715.9	$1,731.7	$1,576.7			
Weather -- Degree Days (a)						
Heating (6,627 Normal)				6,508	6,043	6,628
Cooling (722 Normal)				800	723	949

(a) As measured at Mitchell International Airport in Milwaukee, Wisconsin. Normal degree days are based upon a twenty-year moving average.

Electric Utility Revenues and Sales

2007 vs. 2006:

Our electric utility operating revenues increased by $176.3 million, or 7.0%, when compared to 2006. The biggest drivers of the increase in revenues relate to the recognition of revenues attributable to fuel and purchased power of approximately $37.4 million and increased revenues related to Resale - Utilities of approximately $30.4 million. Our policy for electric fuel revenues is to not recognize revenue for any currently billable amounts if it is probable that we will refund those amounts to customers. In 2006, we experienced lower than expected fuel and purchased power costs, and we established $37.4 million of reserves to reflect amounts that were refunded to customers. No such reserves were established in 2007 as we experienced higher fuel and purchased power costs. The increase in Resale-Utilities reflects our ability to sell electricity into the MISO and PJM markets due to the increased availability of our baseload plants.

In addition, we estimate that $27.1 million of the increase in operating revenues relates to pricing increases. This increase primarily reflects rate increases received in late January 2006 that were in effect for the entire twelve months ended December 31, 2007 and a wholesale rate increase effective May 2007. We also estimate that $28.9 million of the increase was due to more favorable weather and $22.8 million relates to sales growth in residential and commercial sales. Finally, approximately $9.0 million of the increase relates to the settlement in the second quarter of 2007 of a billing dispute with our largest customers, two iron ore mines.

Our retail electric sales volume grew by approximately 2.2%. The increase in retail sales was driven by growth in residential and commercial sales and more favorable weather in 2007 as compared to the same period in 2006. In 2007, heating degree days increased by approximately 7.7% compared to 2006, and cooling degree days increased by approximately 10.7%.

Our electric utility operating revenues are expected to increase in 2008 primarily due to the implementation of the January 2008 Wisconsin retail pricing increase. However, as the primary driver for the pricing increase is increased costs, we do not expect this pricing increase to cause a material increase in earnings. For more information on the pricing increases and the fuel cost adjustment clause, see Utility Rates and Regulatory Matters in Factors Affecting Results, Liquidity and Capital Resources.

2006 vs. 2005:

Our electric utility operating revenues increased by $179.7 million, or 7.6%, when compared to 2005. Revenues in 2006 were $213.3 million higher than 2005 due to pricing increases that we received in January 2006 and during 2005. The most significant pricing increases authorized by the PSCW related to the recovery of higher fuel costs, costs associated with the new plants under our PTF strategy and increased transmission costs.

Our electric sales volumes decreased by 1.8% in 2006 as compared to 2005 due to mild weather and lower commercial and industrial sales, offset by an increase in sales for resale. Residential sales volumes decreased 2.8% due largely to weather. In 2006, heating degree days decreased approximately 8.8% compared to 2005, and cooling degree days decreased approximately 23.8%. We estimate that the weather had an unfavorable impact on operating revenues of approximately $46.5 million when compared to the prior year. Total sales volumes to commercial/industrial customers decreased 2.7% between the comparative periods. Sales volumes to commercial/industrial customers, excluding our two largest customers, decreased 1.4%. Sales volumes in the wholesale class decreased approximately 19% compared to the prior year due, in part, to the expiration of a wholesale contract on December 31, 2005. The increase in sales volumes to other utilities is attributed to the availability of PWGS 1 for all of 2006, which provided additional generation capacity. PWGS 1 was not operational until the third quarter of 2005. Under the Wisconsin Fuel rules, sales to other utilities reduce fuel costs charged to customers.

Electric Fuel and Purchased Power Expenses

2007 vs. 2006:

Our fuel and purchased power expenses increased by $192.1 million, or approximately 24.1%, when compared to 2006. Our total electric sales volume increased by approximately 3.6%, when compared to the twelve months ended December 31, 2006. However, our average fuel and purchased power costs increased by $4.86 per MWh, or approximately 20.6%. The largest factors for the higher cost per MWh are the power purchase agreement entered into in connection with the sale of Point Beach, which increased costs by approximately $47.0 million, increased coal and transportation costs, increased market prices for purchased energy and an increase in production of gas-fired generation used for opportunity sales.

We expect that electric fuel and purchased power expenses in 2008 will be higher than 2007 because of the full year impact of the Point Beach power purchase agreement and expected increases in the cost of coal and related transportation.

2006 vs. 2005:

In 2006, our fuel and purchased power expenses increased by $24.7 million, or approximately 3.2%, when compared to 2005. Our average cost of fuel and purchased power increased from $23.80 per MWh in 2005 to $25.01 per MWh in 2006. The largest factor for the higher cost per MWh was a 24.2% increase in the per MWh cost of coal-fired generation, which includes coal and related transportation costs, between the comparative periods. This increase was partially offset by increased generation from Point Beach and a decrease in the average costs of purchased power and fuel for our natural gas-fired units.

Gas Utility Revenues, Gross Margin and Therm Deliveries

The following table compares our total gas utility operating revenues and gross margin (total gas utility operating revenues less cost of gas sold) during 2007, 2006 and 2005:

Gas Utility Operations	2007	2006	2005

	(Millions of Dollars)		
Operating Revenues	$1,481.2	$1,419.9	$1,417.5
Cost of Gas Sold	1,052.7	1,018.3	1,047.3
Gross Margin	$428.5	$401.6	$370.2

We believe gross margin is a better performance indicator than revenues because changes in the cost of gas sold flow through to revenue under GCRMs. The following table compares our gas utility gross margin and therm deliveries by customer class during 2007, 2006 and 2005:

	Gross Margin			Therm Deliveries		
Gas Utility Operations	2007	2006	2005	2007	2006	2005
	(Millions of Dollars)			(Millions, Except Degree Days)		
Customer Class						
Residential	$273.9	$255.0	$240.5	791.7	727.9	791.0
Commercial/Industrial	93.4	86.0	72.9	461.9	435.9	460.7
Interruptible	2.0	2.0	1.8	22.7	21.3	23.4
Total Retail Gas Sales	369.3	343.0	315.2	1,276.3	1,185.1	1,275.1
Transported Gas	51.7	51.3	48.5	921.6	843.8	893.7
Other Operating	7.5	7.3	6.5	-	-	-
Total	$428.5	$401.6	$370.2	2,197.9	2,028.9	2,168.8
Weather - Degree Days (a)						
Heating (6,627 Normal)				6,508	6,043	6,628

(a) As measured at Mitchell International Airport in Milwaukee, Wisconsin. Normal degree days are based upon a twenty-year moving average.

2007 vs. 2006:

Our gas margins increased by $26.9 million, or 6.7%, between the comparative periods. We estimate that approximately $21.7 million of this increase related to increased sales as a result of more normal winter weather. Temperatures (as measured by heating degree days) were approximately 7.7% colder in 2007 as compared to 2006. As a result, our retail therm deliveries increased approximately 7.7% from 2006. In addition, we estimate that our gas margins improved by $6.6 million due to a rate order that went into effect in the latter part of January 2006 and was effective for the entire twelve months ended December 31, 2007.

We expect our gas margins to increase in 2008 primarily because of pricing increases as a result of the January 2008 rate order. In addition, 2008 gross margins will be impacted by weather and customer demand. For more information on the pricing increases, see Utility Rates and Regulatory Matters in Factors Affecting Results, Liquidity and Capital Resources below.

2006 vs. 2005:

Our gas margin increased by $31.4 million, or 8.5%, between the comparative periods. The increase in gross margin was due, in part, to pricing increases that were granted by the PSCW and implemented in January 2006. The gas pricing increases were primarily granted to recover higher operating costs, including bad debt expenses. We estimate that our gross margin increased between the comparative periods by approximately $53.4 million due to these pricing increases.

The 2006 pricing increases were partially offset by a decline in gas sales volumes that was driven by mild winter weather and by lower customer usage. Temperatures (as measured by heating degree days) were approximately 8.8% warmer in 2006 as compared to 2005. The mild winter weather reduced customer demand for heating. We estimate that the weather decreased our gross margin by approximately $21.0 million between the comparative periods. In 2006, we saw a reduction in normalized use of gas per customer which we believe was caused by high natural gas prices and the continued improvements in energy efficient appliances. During 2006, we estimate this reduction in normalized use decreased our gross margin by approximately $4.9 million. The decrease in volume of transport gas sales was due in part to fuel switching during months where gas commodity prices were high during 2006. Residential therm deliveries decreased 8.0% as compared to 2005, due to warmer weather and a decrease in use per customer that was driven in part by high commodity prices.

Other Operation and Maintenance Expense

2007 vs. 2006:

Our other operation and maintenance expense decreased by $36.9 million, or 3.0%, when compared to 2006. This decrease was primarily because of a decline in nuclear operations of approximately $37.8 million because we owned Point Beach for only nine months in 2007 as compared to a full year in 2006. Additionally, fossil operations decreased by approximately $6.0 million due to fewer planned outages in 2007 as compared to 2006. These decreases were partially offset by an increase of $12.7 million in regulatory amortizations as a result of the January 2006 rate order. The January 2006 rate order covered increased expenses related to transmission costs, bad debt costs and PTF costs.

Our utility operation and maintenance expenses are influenced by wage inflation, employee benefit costs, plant outages and the amortization of regulatory assets. While we expect our 2008 other operation and maintenance costs to decline as a result of the Point Beach sale, we expect a net increase in 2008 costs because of increased amortization of regulatory assets as directed by the January 2008 rate order.

2006 vs. 2005:

Our other operation and maintenance expense increased by $200.7 million, or 19.9%, when compared to 2005. As discussed above, we received pricing increases in January 2006 to cover increased costs. The increases in other operation and maintenance expenses that relate to the pricing increases include higher PTF lease costs of $85.4 million, increased transmission expenses of $62.7 million, increased renewable energy and energy efficiency program expenses of $10.6 million and increased bad debt expenses of $13.7 million. Other operation and maintenance expenses increased approximately $34.7 million due to PWGS 1 operating costs and the timing of scheduled outages and maintenance projects at our coal plants. In 2005, we received approximately $10.0 million as a settlement to resolve a vendor dispute, reducing other operation and maintenance expense in 2005. These increases were partially offset by decreased nuclear operating and maintenance expense. In 2006, we had only one scheduled nuclear refueling outage as compared to two scheduled refueling outages in 2005, which resulted in approximately a $10.9 million decrease in nuclear operation and maintenance expenses between the comparative periods. In addition, the elimination of seams elimination transmission charges, effective March 31, 2006, resulted in reduced costs of approximately $9.5 million for 2006.

Depreciation, Decommissioning and Amortization Expense

2007 vs. 2006:

Depreciation, decommissioning and amortization expense increased by $1.2 million, or 0.4%, when compared to 2006. This increase was the result of increased depreciation for normal plant additions and coal- related environmental controls that were placed in service in November 2006. These increases were partially offset by a reduction in depreciation and decommissioning costs as a result of the sale of Point Beach in September 2007.

We expect depreciation, decommissioning and amortization expense to decline slightly in 2008 because we no longer own Point Beach. This decline is expected to be partially offset by normal plant additions and the addition of new wind generation.

2006 vs. 2005:

Depreciation, decommissioning and amortization expense decreased by $10.1 million, or 3.1%, when compared to 2005. In January 2006, we implemented new depreciation rates approved by the PSCW which reduced annual depreciation expense. We estimate that the new rates reduced annual depreciation expense by approximately $17.0 million, which was offset, in part, by net plant additions in 2006.

Amortization of Gain

In connection with the sale of Point Beach, we recorded a net gain of approximately $902.2 million, representing a net gain on the sale and the decommissioning assets retained by the Company. We reached agreements with our respective regulators whereby we deferred the gain as a regulatory liability as it would be used for the benefit of our customers, primarily in the form of bill credits.

We will amortize the regulatory liability to income as we issue customer bill credits. During 2007, we issued $6.5 million of bill credits to Michigan customers. In 2008 and 2009, we expect to amortize approximately $359.3 million and $255.3 million of the deferred gain, respectively, as we issue additional customer bill credits. In addition, in 2008 the PSCW authorized a one-time amortization of approximately $85.0 million to match the amortization of $85.0 million of regulatory assets, which will be reflected in the first quarter of 2008.

NON-UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

The most significant subsidiary included in this segment is We Power, which constructs and owns power plants associated with our PTF strategy and leases them to Wisconsin Electric. This segment primarily reflects revenues billed under the PWGS 1 lease and the depreciation expense related to PWGS 1.

The following table compares our non-utility energy segment's operating income during 2007, 2006 and 2005:

Non-Utility Energy Segment	2007	2006	2005
		(Millions of Dollars)	

Operating Revenues	$75.7	$69.1	$40.0
Other Operating Expenses			
Other Operation and Maintenance	15.9	14.4	14.4
Depreciation, Decommissioning and Amortization	12.1	11.2	5.9
Property and Revenue Taxes	0.3	0.4	0.2
Operating Income	$47.4	$43.1	$19.5

Note: The PTF lease revenues and lease costs recorded by the non-utility and utility energy segments are eliminated in consolidation.

2007 vs. 2006:

Our non-utility energy segment contributed $47.4 million of operating income in 2007 compared to operating income of $43.1 million in 2006. This increase was primarily related to the Oak Creek coal handling system that was placed into service during the fourth quarter of 2007.

Our non-utility energy segment is expected to generate higher operating income in 2008 as PWGS 2 is anticipated to be placed in service during the second quarter of 2008 and as we recognize a full year of revenue from the Oak Creek coal handling system.

2006 vs. 2005:

Our non-utility energy segment contributed $43.1 million of operating income in 2006 compared to operating income of $19.5 million in 2005. This increase in operating income primarily reflects a full year of operating income from PWGS 1 in 2006, which was placed in service in July 2005.

CORPORATE AND OTHER CONTRIBUTION TO OPERATING INCOME

2007 vs. 2006:

Corporate and other affiliates had an operating loss of $4.9 million in 2007 compared with an operating loss of $7.4 million in 2006. The favorable change was primarily related to our Wispark operations, which had operating income during 2007 as compared to operating losses throughout 2006. In the foreseeable future, we expect to have slight operating losses as we have minimal business operations in this segment.

2006 vs. 2005:

Corporate and other affiliates had an operating loss of $7.4 million in 2006 compared with operating income of $1.0 million in 2005. The operating loss in 2006 was attributable to lower operating earnings at Wispark.

CONSOLIDATED OTHER INCOME AND DEDUCTIONS, NET

The following table identifies the components of consolidated other income and deductions, net during 2007, 2006 and 2005:

Other Income and Deductions, Net	2007	2006	2005
		(Millions of Dollars)	
Carrying Costs	$28.8	$25.0	$20.4
Gain (Loss) on Sale of Property	13.1	3.2	(3.0)
Gain on Sale of Guardian Investment	-	2.8	-
AFUDC - Equity	5.2	14.6	9.2
Other, net	1.8	7.5	2.1
Total Other Income and Deductions, Net	$48.9	$53.1	$28.7

2007 vs. 2006:

Other income and deductions, net decreased by $4.2 million when compared to 2006. The reduction primarily reflects a decrease in AFUDC of $9.4 million in connection with the environmental controls related to the new scrubber placed in service at our Pleasant Prairie Power Plant during the fourth quarter of 2006. This scrubber was installed as part of the implementation of our EPA consent decree. For further information on the consent decree with the EPA, see Note S -- Commitments and Contingencies in the Notes to Consolidated Financial Statements in this report. This reduction was offset, in part, by an increase in gains on sales of property primarily associated with land sold in Northern Wisconsin and the Upper Peninsula of Michigan.

During 2008 we expect to see a significant reduction in Other income and deductions, net because we will stop accruing carrying costs on substantially all of our regulatory assets because the January 2008 rate order included these regulatory assets as a component of rate base.

2006 vs. 2005:

Other income and deductions, net increased by $24.4 million when compared to 2005. The largest increases relate to increased AFUDC - Equity of $5.4 million, capitalized carrying costs of $4.6 million and the pre-tax gain on the sale of our investment in Guardian of $2.8 million. For further information on the sale of Guardian, see Other Matters in Factors Affecting Results, Liquidity and Capital Resources.

CONSOLIDATED INTEREST EXPENSE, NET

Interest Expense	2007	2006	2005
		(Millions of Dollars)	
Gross Interest Costs	$240.9	$212.6	$202.1
Less: Capitalized Interest	73.3	39.9	28.7
Interest Expense, Net	$167.6	$172.7	$173.4

2007 vs. 2006:

Interest expense, net decreased by $5.1 million in 2007 when compared with 2006. Our gross interest costs increased by $28.3 million because of higher debt levels primarily related to our PTF construction program. However, our capitalized interest increased by $33.4 million due to higher levels of construction in progress at our PTF plants, which resulted in a reduction of our net interest expense.

We expect total interest expense in 2008 to increase due to increased debt levels to fund our planned construction activity; however, these increases are expected to be mitigated by increases in our capitalized interest.

2006 vs. 2005:

Interest expense, net decreased by $0.7 million in 2006 when compared with 2005. Our gross interest costs increased by $10.5 million primarily due to increased debt levels; however, our capitalized interest increased by $11.2 million due to higher CWIP balances. In addition, in 2005 we expensed approximately $6.2 million related to the amortization of costs associated with prior debt redemptions. These costs were fully amortized as of July 2005; therefore, there was no similar expense in 2006.

CONSOLIDATED INCOME TAXES

2007 vs. 2006:

Our effective tax rate applicable to continuing operations was 39.2% in 2007 compared to 35.9% in 2006. In 2006, we reversed $5.8 million of valuation allowance associated with state net operating loss carry forwards as we concluded that it was more likely than not that we would realize these benefits. Excluding these items, our 2006 effective tax rate was 37.1%. For further information see Note H -- Income Taxes in the Notes to Consolidated Financial Statements.

We expect our 2008 annual effective tax rate to range between 36% and 38%. The reduction in our effective tax rate is expected to result from the regulatory treatment of production tax deductions and wind credits. These items were considered by the PSCW in setting our rates in the 2008 rate order; therefore, we do not expect the lower effective tax rate to have a significant impact on net income.

2006 vs. 2005:

Our effective tax rate applicable to continuing operations was 35.9% in 2006 compared to 33.0% in 2005. In 2006 and 2005, we reversed $5.8 million and $16.3 million, respectively, of valuation allowance associated with state net operating loss carry forwards as we concluded that it was more likely than not that we would realize these benefits. Excluding these items, our 2006 and 2005 effective tax rate was 37.1% and 36.6%, respectively. For further information see Note H -- Income Taxes in the Notes to Consolidated Financial Statements.

DISCONTINUED OPERATIONS

The following table identifies the primary components of net income (loss) from discontinued operations during 2007, 2006 and 2005.

Discontinued Operations	2007	2006	2005
		(Millions of Dollars)	
Manufacturing	$ -	$2.4	$ -
Non-Utility and Other	(0.9)	1.5	5.1

Income (Loss) from Discontinued Operations, Net of Tax	($0.9)	$3.9	$5.1

Our 2007 loss from discontinued operations reflects a decrease in the resolution of tax liabilities during 2007.

Our 2006 earnings from discontinued operations reflect a loss on the sale of Minergy Neenah, the 2006 operations of the plant and income of approximately $2.4 million related to the favorable resolution of tax liabilities.

Our 2005 earnings from discontinued operations reflect a gain on the sale of the Calumet facility, the favorable resolution of liabilities at Calumet and a downward adjustment to the carrying value of Minergy Neenah.

See Note D -- Asset Sales, Divestitures and Discontinued Operations in the Notes to Consolidated Financial Statements for further information regarding the transactions described above.

LIQUIDITY AND CAPITAL RESOURCES

CASH FLOWS

The following table summarizes our cash flows during 2007, 2006 and 2005:

Wisconsin Energy Corporation	2007	2006	2005
		(Millions of Dollars)	
Cash Provided by (Used in)			
Operating Activities	$532.5	$730.0	$579.0
Investing Activities	($543.2)	($939.5)	($699.2)
Financing Activities	$1.1	$173.3	$157.8

Operating Activities

2007 vs. 2006:

Cash provided by operating activities was $532.5 million during 2007, which is $197.5 million lower than 2006. This decline was due primarily to higher tax payments, lower fuel recoveries and changes in working capital. In 2007, we paid approximately $108 million in cash taxes because of the Point Beach sale and the liquidation of the nuclear decommissioning trust. In addition, cash taxes from operating income were higher due to higher taxable income. Our cash from fuel collections was unfavorable in 2007 as compared to 2006 because in 2006 we over-collected fuel and purchased power costs and in 2007 we under collected such costs.

2006 vs. 2005:

Cash provided by operating activities for 2006 totaled $730.0 million, which is a $151.0 million improvement over 2005. There were two primary areas that drove this improvement in operating cash flows. During 2006, we estimate that our collections of fuel costs improved by nearly $95 million as we had favorable collections in 2006 and unfavorable recoveries and fuel cost deferrals in 2005. The other primary area related to the working capital requirements related to gas in storage. During 2006, we entered into certain contracts that reduced our need to inject gas in storage. In addition, lower gas commodity prices, offset by less withdrawals due to weather, have lowered working capital requirements between the comparative periods. We estimate that these items reduced our cash needs for gas in storage by approximately $77.0 million. Partially offsetting these items was an increase of cash taxes of approximately $107 million due to higher taxable earnings.

Investing Activities

2007 vs. 2006:

Cash used in investing activities was $543.2 million during 2007, an improvement of $396.3 million over 2006. The two most significant factors related to cash used in investing activities related to capital expenditures and the unrestricted proceeds we received from the sale of Point Beach. Our 2007 capital expenditures exceeded $1.2 billion, an increase of $282.8 million over 2006. This increase was expected and it primarily reflects the continued construction efforts with our PTF generation plants.

During 2007, we experienced a significant inflow of cash related to the sale of Point Beach; however, we restricted a significant amount of that cash as it will be used for the benefit of our customers. The 2007 cash flows related to the Point Beach sale are summarized as follows:

	(Millions of Dollars)
Proceeds from the sale of Point Beach	$924.1
Proceeds from the liquidation of decommissioning trusts	552.4
Total Proceeds	1,476.5
Less: Proceeds restricted for the benefit of customers, net of taxes and bill credits	(731.6)
Unrestricted cash to the Company	$744.9

As the gain on the Point Beach sale is given back to customers, primarily in the form of bill credits, we will release the restricted cash. We expect approximately $408 million of restricted cash will be released as the Point Beach gain will be amortized to income in 2008 and the remaining balance will be released and amortized in future years.

2006 vs. 2005:

During 2006, net cash outflows from investing activities were $939.5 million compared with net cash outflows of $699.2 million in 2005. This increase is primarily associated with the increased capital expenditures as construction progresses on our new generating plants. During 2006, we had significant capital expenditures related to the Oak Creek expansion and PWGS 2.

The following table identifies capital expenditures by year:

Capital Expenditures	2007	2006	2005
	(Millions of Dollars)		
Utility	$540.3	$459.9	$458.6
We Power	667.3	466.1	276.4
Other	3.9	2.7	10.1
Total Capital Expenditures	$1,211.5	$928.7	$745.1

Financing Activities

The following table summarizes our cash flows from financing activities:

	2007	2006	2005
	(Millions of Dollars)		
Increase in Debt	$148.4	$299.7	$291.9
Dividends on Common Stock	(116.9)	(107.6)	(102.9)
Common Stock, Net	(31.7)	(21.2)	(28.1)
Other	1.3	2.4	(3.1)
Cash Provided by Financing	$1.1	$173.3	$157.8

2007 vs. 2006:

During 2007, cash provided by financing activities was $1.1 million compared to $173.3 million in 2006. This decline occurred because we did not issue as much net new debt in 2007 as compared to 2006. The decline in the amount of net new debt is directly related to the unrestricted cash we received from the sale of Point Beach as discussed above.

During 2007, we issued $500 million principal amount of Junior Notes and we used the net proceeds from these notes to pay down short-term debt incurred to fund our PTF construction and for other working capital purposes. In December 2007, Wisconsin Electric retired $250 million of 3.50% Notes due December 1, 2007.

2006 vs. 2005:

During 2006, cash provided by financing activities was $173.3 million compared to $157.8 million in 2005. Wisconsin Energy retired at the scheduled maturity date $250.0 million of 5.875% Notes due April 1, 2006. Short-term debt was issued to retire those notes. During 2006, short-term debt increased approximately $455.6 million. In November 2006, Wisconsin Electric issued $300 million of 5.70% Debentures due December 1, 2036. The securities were issued under an existing $665 million shelf registration statement filed with the SEC. The net proceeds from the sale were used to retire Wisconsin Electric's $200 million of 6-5/8% Debentures due November 15, 2006 at their scheduled maturity and to repay outstanding commercial paper incurred for working capital requirements.

No new shares of Wisconsin Energy's common stock were issued in 2007, 2006 or 2005. During 2007, 2006 and 2005, our plan agents purchased, in the open market, 1.4 million shares at a cost of $67.8 million, 1.1 million shares at a cost of $48.0 million and 2.0 million shares at a cost of $75.1 million, respectively, to fulfill exercised stock options and restricted stock awards. In 2007, 2006 and 2005, we received proceeds of $36.1 million, $26.8 million and $47.0 million, respectively, related to the exercise of stock options. In addition, we instructed our independent agents to purchase shares of our common stock in the open market to satisfy our obligation under our dividend reinvestment plan and various employee benefit plans.

For additional information on the Junior Notes and other debt issues, see Note K -- Long-Term Debt in the Notes to Consolidated Financial Statements.

CAPITAL RESOURCES AND REQUIREMENTS

In 2000, we announced a growth strategy which, among other things, called for us to sell non-core assets and reduce our debt levels. Our debt to total capital ratio has decreased from 68.3% at September 30, 2000 to 58.6% at December 31, 2007 due primarily to these asset sales and the sale of Point Beach. For more information, see Note D -- Asset Sales, Divestitures and Discontinued Operations in the Notes to Consolidated Financial Statements in this report. Over the next several years, we expect to have some limited asset sales, but at levels significantly lower than prior years.

Wisconsin Electric is the obligor under two series of insured tax-exempt pollution control refunding bonds in outstanding principal amount of $147 million that were issued in 2004 (the 2004 Bonds). Since the 2004 Bonds were issued, they have borne interest at an "auction rate." Because of substantial disruptions in the auction rate bond market that occurred in early to mid-February, 2008, Wisconsin Electric gave notice on February 15, 2008 of the exercise of its option to purchase all of the 2004 Bonds (in lieu of redemption) on March 4, 2008 at a purchase price of par plus accrued interest to the date of purchase. Wisconsin Electric intends to issue commercial paper to fund the purchase of the 2004 Bonds. Depending on market conditions and other factors, Wisconsin Electric may change the method used to determine the interest rate on the 2004 Bonds and have them remarketed to third parties.

Capital Resources

We anticipate meeting our capital requirements during 2008 and the next several years primarily through internally generated funds and short-term borrowings supplemented by the issuance of intermediate or long-term debt securities depending on market conditions and other factors. Beyond 2008, we anticipate meeting our capital requirements through internally generated funds supplemented, when required, by short-term borrowings and the issuance of debt securities.

In August 2007, Wisconsin Electric filed a shelf registration statement with the SEC to issue up to $800 million in debt securities. The registration statement has been declared effective by the SEC and, subject to market conditions, is available for use.

We have access to capital markets and have been able to generate funds internally and externally to meet our capital requirements. Our ability to attract the necessary financial capital at reasonable terms is critical to our overall strategic plan. We believe that we have adequate capacity to fund our operations for the foreseeable future through our borrowing arrangements, access to capital markets and internally generated cash.

Wisconsin Energy, Wisconsin Electric and Wisconsin Gas credit agreements provide liquidity support for each company's obligations with respect to commercial paper and for general corporate purposes.

As of December 31, 2007, we had approximately $1.7 billion of available unused lines under our bank back-up credit facilities on a consolidated basis and approximately $900.7 million of total consolidated short-term debt outstanding.

We review our bank back-up credit facility needs on an ongoing basis and expect to be able to maintain adequate credit facilities to support our operations. The following table summarizes such facilities at December 31, 2007.

Company	Total Facility	Letters of Credit	Credit Available	Facility Expiration	Facility Term
		(Millions of Dollars)			
Wisconsin Energy	$900.0	$1.5	$898.5	April 2011	5 year
Wisconsin Electric	$500.0	$4.0	$496.0	March 2011	5 year
Wisconsin Gas	$300.0	$-	$300.0	March 2011	5 year

Each of these facilities has a renewal provision for two one-year extensions, subject to lender approval.

The following table shows our capitalization structure as of December 31, 2007 and 2006, as well as an adjusted capitalization structure for 2007 that we believe is consistent with the manner in which the rating agencies currently view the Junior Notes:

	2007				2006	
Capitalization Structure	Actual		Adjusted		Actual	
			(Millions of Dollars)			
Common Equity	$3,099.2	41.0%	$3,349.2	44.3%	$2,889.0	40.1%
Preferred Stock of Subsidiary	30.4	0.4%	30.4	0.4%	30.4	0.4%
Long-Term Debt (including current maturities)	3,525.3	46.7%	3,275.3	43.4%	3,370.1	46.8%
Short-Term Debt	900.7	11.9%	900.7	11.9%	911.9	12.7%
Total Capitalization	$7,555.6	100.0%	$7,555.6	100.0%	$7,201.4	100.0%
Total Debt	$4,426.0		$4,176.0		$4,282.0	

Ratio of Debt to Total Capitalization	58.6%	55.3%	59.5%

Included in Long-Term Debt on our Consolidated Balance Sheet as of December 31, 2007 is $500 million aggregate principal amount of the Junior Notes. The adjusted presentation attributes $250 million of the Junior Notes to Common Equity and $250 million to Long-Term Debt. We believe this presentation is consistent with the 50% equity credit the majority of rating agencies currently attribute to the Junior Notes.

The adjusted presentation of our consolidated capitalization structure is presented as a complement to our capitalization structure presented in accordance with GAAP. Management evaluates and manages Wisconsin Energy's capitalization structure, including its total debt to total capitalization ratio, using the GAAP calculation and the rating agency treatment of the Junior Notes. Therefore, we believe the non-GAAP adjusted presentation reflecting this treatment is useful and relevant to investors in understanding how management and the rating agencies evaluate our capitalization structure.

As described in Note J -- Common Equity, in the Notes to Consolidated Financial Statements, certain restrictions exist on the ability of our subsidiaries to transfer funds to us. We do not expect these restrictions to have any material effect on our operations or ability to meet our cash obligations.

Access to capital markets at a reasonable cost is determined in large part by credit quality. The following table summarizes the ratings of our debt securities and the debt securities and preferred stock of our subsidiaries by S&P, Moody's and Fitch as of December 31, 2007:

	S&P	Moody's	Fitch
Wisconsin Energy			
Commercial Paper	A-2	P-2	F2
Unsecured Senior Debt	BBB+	A3	A-
Unsecured Junior Notes	BBB-	Baa1	BBB+
Wisconsin Electric			
Commercial Paper	A-2	P-1	F1
Secured Senior Debt	A-	Aa3	AA-
Unsecured Debt	A-	A1	A+
Preferred Stock	BBB	A3	A
Wisconsin Gas			
Commercial Paper	A-2	P-1	F1
Unsecured Senior Debt	A-	A1	A+

Wisconsin Energy Capital Corporation			
Unsecured Debt	BBB+	A3	A-

In July 2007, S&P affirmed the corporate credit ratings of Wisconsin Energy, Wisconsin Electric, Wisconsin Gas and Wisconsin Energy Capital Corporation and revised the ratings outlooks assigned each company from negative to stable.

On June 15, 2006, Fitch affirmed the security ratings of Wisconsin Energy, Wisconsin Electric, Wisconsin Gas and Wisconsin Energy Capital Corporation and changed the security ratings outlook for Wisconsin Energy and Wisconsin Energy Capital Corporation from stable to negative. The security ratings outlooks assigned by Fitch for Wisconsin Electric and Wisconsin Gas are stable.

The security rating outlooks assigned by Moody's for Wisconsin Energy, Wisconsin Electric, Wisconsin Gas and Wisconsin Energy Capital Corporation are all stable.

We believe these security ratings should provide a significant degree of flexibility in obtaining funds on competitive terms. However, these security ratings reflect the views of the rating agencies only. An explanation of the significance of these ratings may be obtained from each rating agency. Such ratings are not a recommendation to buy, sell or hold securities, but rather an indication of creditworthiness. Any rating can be revised upward or downward or withdrawn at any time by a rating agency if it decides that the circumstances warrant the change. Each rating should be evaluated independently of any other rating.

Capital Requirements

Our estimated 2008, 2009 and 2010 capital expenditures are as follows:

Capital Expenditures	2008	2009	2010	
		(Millions of Dollars)		
Utility	$662.3	$592.4	753.3	We Power
				516.5
				217.2
				40.3
				Other
				4.6
				6.8
				4.3

Total
$1,183.4
$816.4
$797.9

Due to changing environmental and other regulations such as air quality standards and electric reliability initiatives that impact our utility energy segments, future long-term capital requirements may vary from recent capital requirements.

Our capital requirements include the construction of the PTF units. Through December 31, 2007, we have expended approximately $2.0 billion of the approximately $2.6 billion in capital we estimate will be required to construct the 2,120 MW of new natural gas-fired and coal-fired generating capacity. We anticipate that all of the PTF units will be completed during 2010.

We expect the capital requirements to support our investment in new generation under PTF to come from a combination of internal and external sources. We Power, a non-utility subsidiary, is constructing the new generating plants, which will be leased to Wisconsin Electric under 25-30 year lease agreements. We expect that Wisconsin Electric will recover the lease payments in its utility rates.

In June 2005, we purchased the development rights to a wind farm project (Blue Sky Green Field) from Navitas Energy, Inc. After receiving the necessary approvals and permits, we began construction in June 2007. Wind turbine components began arriving at the site during the fourth quarter of 2007. We estimate that this project will add 145 MW of generating capacity and the capital cost of the project, excluding AFUDC, will be approximately $300 million. We currently expect the wind turbines to be placed into service by the second quarter of 2008.

In addition, in October 2007 we provided notice to FPL Energy, a subsidiary of FPL, that we were exercising the option we received in connection with the sale of Point Beach to purchase all rights to a new wind farm site in central Wisconsin. Once the purchase is complete, we will proceed with securing approvals and permits for construction and operation, and we expect to install wind turbines with approximately 100 MW of generating capacity. We expect the wind turbines to be placed into service between late 2010 or 2011, subject to regulatory approvals and turbine availability.

Investments in Outside Trusts:

We have funded our pension obligations and certain other post-retirement obligations in outside trusts. Collectively, these trusts had investments that exceeded $1.2 billion as of December 31, 2007. These trusts hold investments that are subject to the volatility of the stock market and interest rates. For further information see Note O -- Benefits in the Notes to Consolidated Financial Statements.

Off-Balance Sheet Arrangements:

We are a party to various financial instruments with off-balance sheet risk as a part of our normal course of business, including financial guarantees and letters of credit which support construction projects, commodity contracts and other payment obligations. We believe that these agreements do not have, and are not reasonably likely to have, a current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to our investors. For further information, see Note P -- Guarantees in the Notes to Consolidated Financial Statements.

We have identified three tolling and purchased power agreements with third parties but have been unable to determine if we are the primary beneficiary of any of these three variable interest entities as defined by FIN 46. As a result, we do not consolidate these entities. Instead, we account for one of these contracts as a capital lease and for the other two contracts as operating leases as reflected in the table below. We have included our contractual obligations under all three of these contracts in our Contractual Obligations/Commercial Commitments disclosure that follows. For additional information, see Note G -- Variable Interest Entities in the Notes to Consolidated Financial Statements.

Contractual Obligations/Commercial Commitments:

We have the following contractual obligations and other commercial commitments as of December 31, 2007:

	Payments Due by Period				
Contractual Obligations (a)	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
	(Millions of Dollars)				
Long-Term Debt Obligations (b)	$6,484.7	$543.5	$414.9	$758.5	$4,767.8
Capital Lease Obligations (c)	437.5	33.6	71.1	76.5	256.3
Operating Lease Obligations (d)	135.1	37.0	44.3	35.4	18.4
Purchase Obligations (e)	14,280.1	1,386.3	1,772.4	889.1	10,232.3
Other Long-Term Liabilities (f)	85.6	83.4	1.5	0.7	-
Total Contractual Obligations	$21,423.0	$2,083.8	$2,304.2	$1,760.2	$15,274.8

(a) The amounts included in the table are calculated using current market prices, forward curves and other estimates. Contracts with multiple unknown variables have been omitted from the analysis.

(b) Principal and interest payments on our Long-Term Debt and the Long-Term Debt of our affiliates (excluding capital lease obligations). For the purpose of determining our contractual obligations and commercial commitments only, we assumed the Junior Notes would be retired in 2017 with the proceeds from the issuance of qualifying securities pursuant to the terms of the RCC.

(c) Capital Lease Obligations of Wisconsin Electric for power purchase commitments.

(d) Operating Lease Obligations for power purchase commitments and vehicle and rail car leases for Wisconsin Energy and affiliates.

(e) Purchase Obligations under various contracts for the procurement of fuel, power, gas supply and associated transportation related to utility operations and for construction, information technology and other services for utility and We Power operations. This includes the power purchase agreement for all of the energy produced by Point Beach.

(f) Other Long-Term Liabilities includes the expected 2008 supplemental executive retirement plan obligation and the non-discretionary pension contribution. For additional information on employer contributions to our benefit plans see Note O -- Benefits in the Notes to Consolidated Financial Statements.

The table above does not include FIN 48 liabilities. For further information regarding FIN 48 liabilities, refer to Note H -- Income Taxes in the Notes to Consolidated Financial Statements in this report.

Obligations for utility operations by our utility affiliates have historically been included as part of the rate making process and therefore are generally recoverable from customers. For a discussion of 2008, 2009 and 2010 estimated capital expenditures, see Capital Requirements above.

FACTORS AFFECTING RESULTS, LIQUIDITY AND CAPITAL RESOURCES

MARKET RISKS AND OTHER SIGNIFICANT RISKS

We are exposed to market and other significant risks as a result of the nature of our businesses and the environment in which those businesses operate. These risks, described in further detail below, include but are not limited to:

Large Construction Projects:

In December 2002, the PSCW issued a written order granting a CPCN to commence construction of the PWGS consisting of two 545 MW natural gas-fired combined cycle generating units on the site of Wisconsin Electric's existing Port Washington Power Plant. The order approved key financial terms of the leased

generation contracts including fixed construction costs of PWGS 1 at $309.6 million and PWGS 2 at $280.3 million

(2001 dollars), respectively, subject to escalation at the GDP inflation rate, force majeure, excused events and event of loss provisions. For additional information, see *Power the Future* -- Port Washington.

In addition, in November 2003, the PSCW issued a written order granting a CPCN to commence construction of two 615 MW super critical pulverized coal generating units adjacent to the site of Wisconsin Electric's existing Oak Creek Power Plant. The order approves key financial terms of the leased generation contracts including a target construction cost of the Oak Creek expansion of $2.191 billion, plus, subject to PSCW approval, cost over-runs of up to 5%, costs attributable to force majeure events, excused events and event of loss provisions. For additional information, see *Power the Future* -- Oak Creek Expansion.

Large construction projects of this type are subject to usual construction risks over which we will have limited or no control and which might adversely affect project costs and completion time. These risks include, but are not limited to, shortages of, the inability to obtain or the cost of labor or materials, the inability of the general contractor or subcontractors to perform under their contracts, strikes, adverse weather conditions, continuing legal challenges and appeals to granted permits, including the WPDES permit granted in connection with the Oak Creek expansion,, changes in applicable laws or regulations, adverse interpretation or enforcement of permit conditions, laws and regulations by the courts or permitting agencies, the inability to obtain necessary operating permits in a timely manner, other governmental actions and events in the global economy.

If final costs for the construction of PWGS exceed the fixed costs allowed in the PSCW order, absent a finding by the PSCW of extraordinary circumstances such as force majeure conditions, this excess will not adjust the amount of the lease payments recovered from Wisconsin Electric. If final costs of the Oak Creek expansion are within 5% of the target cost, and the additional costs are deemed to be prudent by the PSCW, the final lease payments for the Oak Creek expansion recovered from Wisconsin Electric would be adjusted to reflect the actual construction costs. Costs above the 5% cap would not be included in lease payments or recovered from customers absent a finding by the PSCW of extraordinary circumstances such as force majeure conditions.

Regulatory Recovery:

The electric operations of Wisconsin Electric burn natural gas in its leased power plants, in several of its peaking power plants and as a supplemental fuel at several coal-fired plants. In addition, the cost of purchased power is generally tied to the cost of natural gas. Wisconsin Electric bears regulatory risk for the recovery of these fuel and purchased power costs when these costs are higher than the base rate established in its rate structure. For further information on the recovery of fuel and purchase power costs see Commodity Prices below.

Our utility energy segment accounts for its regulated operations in accordance with SFAS 71. Our rates are determined by regulatory authorities. Our primary regulator is the PSCW. SFAS 71 allows regulated entities to defer certain costs that would otherwise be charged to expense, if the regulated entity believes the recovery of these costs is probable. We record regulatory assets pursuant to specific orders or by a generic order issued by our regulators, and recovery of these deferred costs in future rates is subject to the review and approval of those regulators. We assume the risks and benefits of ultimate recovery of these items in future rates. If the recovery of these costs is not approved by our regulators, the costs are charged to income in the current period. We expect to recover our outstanding regulatory assets in rates over a period of no longer than 20 years. Regulators can impose liabilities on a prospective basis for amounts previously collected from customers and for amounts that are expected to be refunded to customers. Under SFAS 71, we record these items as regulatory liabilities.

Commodity Prices:

In the normal course of providing energy, we are subject to market fluctuations of the costs of coal, natural gas and the cost of purchased power. We manage our fuel and gas supply costs through a portfolio of short and long-term procurement contracts with various suppliers for the purchase of coal, natural gas and fuel oil. In addition, we manage the risk of price volatility by utilizing gas and electric hedging programs.

Wisconsin's retail electric fuel cost adjustment procedure mitigates some of Wisconsin Electric's risk of electric fuel cost fluctuation. If cumulative fuel and purchased power costs for electric utility operations deviate from a prescribed range when compared to the costs projected in the most recent retail rate proceeding, retail electric rates may be adjusted prospectively. For 2008, we will operate under a traditional fuel cost adjustment clause in the Wisconsin retail jurisdiction whereby fuel revenues may be adjusted prospectively if fuel and purchased power costs

fall outside a pre-established annual band of plus or minus 2%. For information regarding the 2008 fuel rules, see Utility Rates and Regulatory Matters.

The PSCW has authorized dollar for dollar recovery for the majority of natural gas costs for our gas utility operations through gas cost recovery mechanisms, which mitigates most of the risk of gas cost variations. For information concerning the electric utility fuel cost adjustment procedure and the natural gas utilities' GCRMs, see Utility Rates and Regulatory Matters.

Natural Gas Costs:

Significant increases in the cost of natural gas affect our electric and gas utility operations. Natural gas costs have increased because the supply of natural gas in recent years has not kept pace with the demand for natural gas. We expect that demand for natural gas will remain high into the foreseeable future and that significant price relief will not occur until additional natural gas resources are developed.

Higher natural gas costs increase our working capital requirements and result in higher gross receipts taxes in the State of Wisconsin. Higher natural gas costs combined with slower economic conditions also expose us to greater risks of accounts receivable write-offs as more customers are unable to pay their bills. Because federal and state energy assistance dollars have not kept pace with rising natural gas costs over the recent year, our risks related to bad debt expenses have increased.

In February 2005, the PSCW authorized the use of the escrow method of accounting for bad debt costs allowing for deferral of Wisconsin residential bad debt expense that exceed amounts allowed in rates. This authorization extends through March 2009.

As a result of GCRMs, our gas distribution subsidiaries receive dollar for dollar recovery on the cost of natural gas. However, increased natural gas costs increase the risk that customers will switch to alternative fuel sources, which could reduce future gas margins.

Weather:

Our Wisconsin utility rates are set by the PSCW based upon estimated temperatures which approximate 20-year averages. Wisconsin Electric's electric revenues are unfavorably sensitive to below normal temperatures during the summer cooling season, and to some extent, to above normal temperatures during the winter heating season. Our gas revenues are unfavorably sensitive to above normal temperatures during the winter heating season. A summary of actual weather information in the utility segment's service territory during 2007, 2006 and 2005, as measured by degree-days, may be found above in Results of Operations.

Interest Rate:

We have various short-term borrowing arrangements to provide working capital and general corporate funds. We also have variable rate long-term debt outstanding at December 31, 2007. Borrowing levels under these arrangements vary from period to period depending upon capital investments and other factors. Future short-term interest expense and payments will reflect both future short-term interest rates and borrowing levels.

We performed an interest rate sensitivity analysis at December 31, 2007 of our outstanding portfolio of $900.7 million of short-term debt with a weighted average interest rate of 5.18% and $164.4 million of variable-rate long-term debt with a weighted average interest rate of 4.39%. A one-percentage point change in interest rates would cause our annual interest expense to increase or decrease by approximately $9.0 million before taxes from short-term borrowings and $1.6 million before taxes from variable rate long-term debt outstanding.

Marketable Securities Return:

We fund our pension and OPEB obligations through various trust funds, which in turn invest in debt and equity securities. Changes in the market prices of these assets can affect future pension and OPEB expenses. Additionally, future contributions can also be affected by changes in the market price of trust fund assets. We expect that the risk of expense and contribution variations as a result of changes in the market price of trust fund assets would be mitigated in part through future rate actions by our various utility regulators. Through December 31, 2005, we were operating under a PSCW-ordered, qualified five-year rate restriction period. For further information about the rate restriction, see Utility Rates and Regulatory Matters.

At December 31, 2007, we held the following total trust fund assets at fair value, primarily consisting of publicly traded debt and equity security investments:

Wisconsin Energy Corporation	Millions of Dollars
Pension trust funds	$1,007.2
Other post-retirement benefits trust funds	$201.5

Fiduciary oversight of the pension and OPEB trust fund investments is the responsibility of an Investment Trust Policy Committee. Qualified external investment managers are engaged to manage the investments. Asset/liability studies are periodically conducted with the assistance of an outside investment advisor. The current study for the pension fund projects long-term annualized returns of approximately 8.5%.

Credit Ratings:

We do not have any credit agreements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. We do have certain agreements in the form of commodity contracts and employee benefit plans that could require collateral or a termination payment only in the event of a credit rating change to below investment grade. At December 31, 2007, we estimate that the collateral or the termination payment required under these agreements totaled approximately $204.0 million. In addition, we have commodity contracts that in the event of a credit rating downgrade could result in a reduction of our unsecured credit granted by counterparties.

Economic Conditions:

We are exposed to market risks in the regional midwest economy for our utility energy segment. Utility sales growth is impacted by Wisconsin employment and industrial production demand.

Inflation:

We continue to monitor the impact of inflation, especially with respect to the rising costs of medical plans, fuel, transmission access, construction costs, regulatory and environmental compliance and new generation in order to minimize its effects in future years through pricing strategies, productivity improvements and cost reductions. We have expectations of slightly elevated inflation in these costs and resultant energy costs in the near future. We do not believe the impact of general inflation will have a material impact on our future results of operations.

For additional information concerning risk factors, including market risks, see the Cautionary Statement Regarding Forward-Looking Information at the beginning of this report and Risk Factors in Item 1A.

POWER THE FUTURE

Under our PTF strategy, we expect to meet a significant portion of our future generation needs through the construction of the PWGS and the Oak Creek expansion by We Power. We Power will lease the new plants to Wisconsin Electric under long-term leases, and we expect Wisconsin Electric to recover the lease payments in its electric rates.

The PTF units include PWGS 1, PWGS 2, OC 1 and OC 2. The following table identifies certain key items related to the units:

Unit Name	Expected In Service	Authorized Cash Costs (a)
PWGS 1	July 2005 (Actual)	$ 333 million (Actual)
PWGS 2	Second Quarter 2008	$ 329 million
OC 1	2009	$ 1,300 million
OC 2	2010	$ 640 million

(a) Authorized cash costs represent the PSCW approved costs and the increases for factors such as inflation as identified in the PSCW approved lease terms for PWGS 2, and adjusted for our ownership percentages in the case of OC 1 and OC 2.

The lease payments are based on the cash costs authorized by the PSCW. Under the lease terms, our return is calculated using a 12.7% return on equity and the equity ratio is assumed to be 53% for the PWGS Units and 55% for the OC Units. The interest component of the return is determined up to 180 days prior to the date that the units are placed in service.

Power the Future -

Port Washington

Background:

In December 2002, the PSCW issued a written order (the Port Order) granting Wisconsin Energy, Wisconsin Electric and We Power a CPCN to commence construction of the PWGS consisting of two 545 MW natural gas-fired combined cycle generating units on the site of Wisconsin Electric's existing Port Washington Power Plant. The Port Order also authorized Wisconsin Gas to proceed with the construction of a connecting natural gas lateral, which was completed in December 2004, and it authorized ATC to construct transmission system upgrades to serve PWGS 1 and PWGS 2. PWGS 1 was completed in July 2005 and placed into service at that time. PWGS 1 was completed within the PSCW approved cost parameters. In October 2003, we received approval from FERC to transfer by long-term lease certain associated FERC jurisdictional transmission related assets from We Power to Wisconsin Electric. Construction of PWGS 2 is well underway. Site preparation, including removal of the old coal units at the site, was completed in early 2006, and all of the major components have been procured. The unit is expected to begin commercial operation in the second quarter of 2008.

Lease Terms:

The PSCW approved the lease agreements and related documents under which Wisconsin Electric will staff, operate and maintain PWGS 1 and PWGS 2. Key terms of the leased generation contracts include:

- Initial lease term of 25 years with the potential for subsequent renewals at reduced rates;
- Cost recovery over a 25 year period on a mortgage basis amortization schedule;
- Imputed capital structure of 53% equity, 47% debt;
- Authorized rate of return of 12.7% after tax on equity;
- Fixed construction cost of PWGS 1 and PWGS 2 at $309.6 million and $280.3 million (2001 dollars) subject to escalation at the GDP inflation rate;
- Recovery of carrying costs during construction; and
- Ongoing PSCW supervisory authority over those lease terms and conditions specifically identified in the Port Order, which do not include the key financial terms.

In January 2003, Wisconsin Electric filed a request with the PSCW to defer costs for recovery in future rates. The PSCW approved the request in an open meeting in April 2003. We Power began collecting certain costs from Wisconsin Electric in the third quarter of 2003 as provided for in lease generation contracts that were signed in May 2003. We defer the lease costs on our balance sheet, and we amortize the costs to expense as we recover the costs in rates.

Legal and Regulatory Matters:

There are currently no legal challenges to the construction of PWGS and all construction permits have been received for PWGS 1 and PWGS 2. As a result of the enactment of the Energy Policy Act, FERC, through an amendment to Section 203 of the Federal Power Act, has been given jurisdiction over the acquisition of generation (which includes leasing generation), an activity that previously was not subject to FERC's jurisdiction. Under FERC's rules implementing the Energy Policy Act, Wisconsin Energy, Wisconsin Electric and We Power filed a joint application for FERC authorization to transfer the generating assets and limited interconnection facilities of PWGS 2 through a lease arrangement between We Power and Wisconsin Electric. We received approval from FERC for this asset transfer in December 2006.

Power the Future -

Oak Creek Expansion

Background:

In November 2003, the PSCW issued an order (the Oak Creek Order) granting Wisconsin Energy, Wisconsin Electric and We Power a CPCN to commence construction of two 615 MW coal-fired units (the Oak Creek expansion) to be located adjacent to the site of Wisconsin Electric's existing Oak Creek Power Plant. We anticipate OC 1 will be operational in 2009 and OC 2 will be operational in 2010. The Oak Creek Order concluded, among other things, that there was a need for additional electric generation for Southeastern Wisconsin and that a diversity of fuel sources best serves the interests of the State. The total cost for the two units was set at $2.191 billion, and the order provided for recovery of excess costs of up to 5% of the total project, subject to a prudence review by the PSCW. The CPCN was granted contingent upon us obtaining the necessary environmental permits. All necessary permits have been received at this time. In June 2005, construction commenced at the site. In November 2005, we completed the sale of approximately a 17% interest in the project to two unaffiliated entities, who will share ratably in the construction costs.

The Oak Creek expansion includes a new coal handling system that will serve both the existing units at Oak Creek and OC 1 and OC 2. The new coal handling system was placed into service during the fourth quarter of 2007 at a cost of approximately $171.2 million.

Lease Terms:

In October 2004, the PSCW approved the lease generation contracts between Wisconsin Electric and We Power for the Oak Creek expansion. Key terms of the leased generation contracts include:

- Initial lease term of 30 years with the potential for subsequent renewals at reduced rates;
- Cost recovery over a 30 year period on a mortgage basis amortization schedule with the potential for subsequent renewals at reduced rates;
- Imputed capital structure of 55% equity, 45% debt;
- Authorized rate of return of 12.7% after tax on equity;
- Recovery of carrying costs during construction; and
- Ongoing PSCW supervisory authority over those lease terms and conditions specifically identified in the Oak Creek Order, which do not include the key financial terms.

Legal and Regulatory Matters:

The CPCN granted for the construction of the Oak Creek expansion was the subject of a number of legal challenges by third parties; these legal challenges were resolved in June 2005. We have received all permits necessary to commence construction, which began in June 2005. Certain of these permits continue to be contested, but remain in effect unless and until overturned by a reviewing court or ALJ.

A contested case hearing for the WPDES permit was held in March 2006. The ALJ upheld the issuance of the permit in a decision issued in July 2006. In August 2006, the opponents filed in Dane County Circuit Court for judicial review of the ALJ's decision upholding the issuance of the permit. In March 2007, the Dane County Circuit Court affirmed in part the decision by the ALJ to uphold the WDNR's issuance of the permit. The Court also remanded certain aspects of the ALJ's decision for further consideration based on the January 2007 decision by the Federal Court of Appeals for the Second Circuit concerning the federal rule on cooling water intake systems for existing facilities (the Phase II rule) (*Riverkeeper, Inc. v. EPA*, 475 F.3d 83 (2d Cir. 2007)). The Second Circuit found certain portions of the Phase II rule impermissible and remanded several parts of the Phase II rule to the EPA for further consideration or potential additional rulemaking. Consistent with its announcement in March, in July 2007, the EPA formally suspended the Phase II rule in its entirety and directed states to use their "best professional judgment" in evaluating intake systems for existing facilities.

In November 2007, the ALJ determined that the two additional coal-fired units, OC 1 and OC 2, are new facilities under Section 316(b) of the Clean Water Act. The ALJ did not vacate the WPDES permit or any other permit necessary to continue construction of the two units, pointing out that, based upon the present record, the water intake system currently under construction as part of the Oak Creek expansion may be permittable under the standards that apply to new facilities.

The ALJ remanded the WPDES permit to the WDNR and directed the WDNR to reissue or modify the permit to reflect "best technology available" to comply with the standards applicable to new facilities under Wisconsin state law. As part of the decision, the ALJ restated his prior opinion that the water intake system currently under construction may not be operated until the Wisconsin Division of Hearings and Appeals hears any challenge to a reissued or modified permit.

We believe that there are alternatives under the EPA rule for new facilities that would permit the use of the once-through cooling system under construction rather than the use of cooling towers. We have requested that the WDNR issue a modified permit that authorizes the use of the once-through cooling system under the Phase I rule, have submitted information in support of that request and anticipate making additional information submissions in the near future. We anticipate that the WDNR will issue a modified permit in the first half of 2008. At this time, we cannot predict with certainty what the WDNR's decision will be. A re-issued or modified permit will be subject to a public comment period and can be challenged in a hearing before the Wisconsin Division of Hearings and Appeals

or through judicial review. While the process for modifying the WPDES permit proceeds, we will continue construction of OC 1 and OC 2 on the current schedule.

In addition, we filed in Milwaukee County Circuit Court a petition for judicial review of the ALJ's decision. We took this action, even though we did not believe that the ALJ's decision is a "final order" that is reviewable, to ensure that we did not lose our right to appeal. The City of Oak Creek and the WDNR also filed petitions for judicial review and the petitions were consolidated into a single case. At the time that we filed our petition for review, we also filed a motion requesting a determination from the court that the ALJ order is not final and, therefore, not subject to judicial review at this time. On February 11, 2008, the Court granted our motion dismissing the three petitions for review on the grounds that the ALJ's decision is not a final order and further ruled that all issues decided by the ALJ may be judicially reviewed when there is a final agency decision.

As a result of the enactment of the Energy Policy Act, FERC, through an amendment to Section 203 of the Federal Power Act, has been given jurisdiction over the acquisition of generation (which includes leasing generation), an activity that previously was not subject to FERC's jurisdiction. Under FERC's rules implementing the Energy Policy Act, Wisconsin Energy, Wisconsin Electric and We Power filed a joint application for FERC authorization to transfer the generating assets and limited interconnection facilities of OC 1 and OC 2 through a lease arrangement between We Power and Wisconsin Electric. We received approval from FERC on these leases in December 2006.

UTILITY RATES AND REGULATORY MATTERS

The PSCW regulates our retail electric, natural gas, steam and water rates in the State of Wisconsin, while FERC regulates our wholesale power, electric transmission and interstate gas transportation service rates. The MPSC regulates our retail electric rates in the State of Michigan. Within our regulated segment, we estimate that approximately 88% of our electric revenues are regulated by the PSCW, 5% are regulated by the MPSC and the balance of our electric revenues is regulated by FERC. All of our natural gas and water revenues are regulated by the PSCW. Orders from the PSCW can be viewed at http://psc.wi.gov/ and orders from the MPSC can be viewed at www.michigan.gov/mpsc/.

The table below summarizes the anticipated annualized revenue impact of the recent Wisconsin Electric rate changes:

Service - Wisconsin Electric	Incremental Annualized Revenue Increase	Percent Change in Rates	Effective Date
	(Millions)		
Retail electric, Wisconsin	$389.1	17.2%	January 17, 2008
Retail gas, Wisconsin	$4.0	0.6%	January 17, 2008
Retail steam, Wisconsin	$3.6	11.2%	January 17, 2008
Retail electric, Michigan	$0.3	0.6%	May 23, 2007
Fuel electric, Michigan	$3.4	7.5%	January 1, 2007
Retail electric, Wisconsin	$222.0	10.6%	January 26, 2006
Retail gas, Wisconsin	$21.4	2.9%	January 26, 2006
Retail steam, Wisconsin	$7.8	31.5%	January 26, 2006
Fuel electric, Michigan	$2.7	5.9%	January 1, 2006
Fuel electric, Wisconsin	$7.7	0.3%	November 24, 2005
Fuel electric, Michigan	$2.5	5.8%	November 1, 2005
Retail electric, Wisconsin	$59.7	3.1%	May 19, 2005
Retail steam, Wisconsin	$0.5	3.6%	May 19, 2005
Fuel electric, Wisconsin	$114.9	5.9%	March 18, 2005
Fuel electric, Michigan	$3.4	8.0%	January 1, 2005

2008 Pricing

: During 2007, Wisconsin Electric and Wisconsin Gas initiated rate proceedings. Wisconsin Electric asked the PSCW to approve a comprehensive plan which would result in price increases of $648.6 million for its electric customers in Wisconsin. This price increase would be reduced by expected bill credits resulting from the sale of Point Beach. The initial rate filing estimated bill credits of $371.0 million in 2008 and $187.5 million in 2009, resulting in net pricing increases of 7.5% in 2008 and 7.5% in 2009. In addition, Wisconsin Electric requested a 1.8% price increase in 2008 for its gas customers and an approximately 16.0% price increase in 2008 for all steam customers in Milwaukee. Wisconsin Gas filed for a 4.1% price increase in 2008 for its gas customers.

Electric pricing increases were needed to allow us to continue progress on previously approved initiatives, including: costs associated with our new PTF plants; recovery of costs associated with transmission; compliance with environmental regulations; continuation of investment in renewable and efficiency programs, including the new wind facilities approved by the PSCW in February 2007; and scheduled recovery of regulatory assets.

On January 17, 2008, the PSCW approved pricing increases for Wisconsin Electric and Wisconsin Gas as follows:

- $389.1 million (17.2%) in electric rates for Wisconsin Electric - the pricing increase will be offset by $315.9 million in bill credits in 2008 and $240.7 million in bill credits in 2009, resulting in a net increase of $73.2 million (3.2%) and $75.2 million (3.2%), respectively;
- $4.0 million (0.6%) for natural gas service from Wisconsin Electric;
- $3.6 million (11.2%) for steam service from Wisconsin Electric; and
- $20.1 million (2.2%) for natural gas service from Wisconsin Gas.

In addition, the PSCW lowered the return on equity for Wisconsin Electric and Wisconsin Gas from 11.2% to 10.75%. The PSCW also determined that $85.0 million of the Point Beach proceeds should be immediately applied to offset certain regulatory assets.

Wisconsin Electric expects to provide a total of approximately $669.7 million of bill credits to its Wisconsin customers over the three year period ending 2010.

Michigan Price Increase Request

: On January 31, 2008, Wisconsin Electric filed a rate increase request with the MPSC. This request represents an increase in electric rates of 14.7%, or $22.0 million, to support the growing demand for electricity, continued investment in renewable programs, compliance with environmental regulations, addition of distribution infrastructure and increased operational expenses. This filing also includes a request for immediate rate relief of 5.6%, or approximately $8.4 million. We expect an order from the MPSC during the third quarter of 2008.

2006 Pricing:

In January 2006, Wisconsin Electric received an order from the PSCW that allowed it to increase annual electric revenues by approximately $222.0 million, or 10.6%, to recover increased costs associated with investments in our PTF units, transmission services and fuel and purchased power, as well as costs associated with additional sources of renewable energy. The rate increase was based on an authorized return on equity of 11.2%. The order also required Wisconsin Electric to refund to customers, with interest, any fuel revenues that it receives that are in excess of fuel and purchased power costs that it incurs, as defined by the Wisconsin fuel rules. The original order stipulated that any refund would also include interest at short-term rates. This refund provision did not extend past December 31, 2006.

During 2006, we experienced lower than expected fuel and purchased power costs. In September 2006, we requested and received approval from the PSCW to refund favorable fuel recoveries including accrued interest at a short-term rate. In addition, in September 2006 the PSCW determined that if the total recoveries for 2006 exceeded $36 million, interest on the amount in excess of $36 million would be paid at the rate of 11.2%, our authorized return on equity rather than at short-term rates as originally set forth in the order. During October 2006, we refunded $28.7 million, including interest, to Wisconsin retail customers as a credit on their bill and we received approval from the PSCW to refund an additional $10 million, including interest, in the first quarter of 2007.

During 2007, Wisconsin Electric operated under a traditional fuel cost adjustment clause in the Wisconsin retail jurisdiction whereby fuel revenues could have been adjusted prospectively if fuel and purchased power costs fell outside a pre-established annual band of plus or minus 2%.

Our gas operations went through a traditional rate proceeding whereby the revenues were set to recover projected costs and to provide a return on rate base. The January 2006 order provided for increases in gas revenues totaling $60.1 million ($21.4 million or 2.9% for Wisconsin Electric gas operations and $38.7 million or 3.7% for Wisconsin Gas gas operations). The rate increases were based on an authorized return on equity of 11.2% for the gas operations of both Wisconsin Electric and Wisconsin Gas.

The steam rate proceeding was a traditional rate proceeding. The January 2006 order provided for an increase in steam rates of $7.8 million, or 31.5%, to be phased in over a two year period beginning in 2006. The rate increase was based on an authorized return on equity of 11.2%.

Limited Rate Adjustment Requests

2005 Fuel Recovery Filing:

In February 2005, Wisconsin Electric filed an application with the PSCW for an increase in electric rates in the amount of $114.9 million due to the increased costs of fuel and purchased power as a result of customer growth and the increase in the reliance upon natural gas as a fuel source. We received approval for the increase in fuel recoveries on an interim basis in March 2005. In November 2005, we received the final rate order, which authorized an additional $7.7 million in rate increases, for a total increase of $122.6 million (6.2%). In December 2005, two parties filed suit against the PSCW in Dane County Circuit Court challenging the PSCW's decision to allow fuel cost recovery, while allowing us to keep the savings that resulted from the WICOR acquisition. As a condition of the PSCW approval of the WICOR acquisition, Wisconsin Electric and Wisconsin Gas were restricted from increasing Wisconsin rates for a five year period ending December 31, 2005, with certain limited exceptions, but we were allowed to keep the savings generated from the merger. In July 2006, the Dane County Circuit Court affirmed the PSCW's decision. In August 2006, the opponents appealed this decision to the Wisconsin Court of Appeals. In July 2007, the Court of Appeals affirmed the Dane County Circuit Court decision upholding the PSCW order. The time period for appeal has expired and no appeals were filed.

2005 Revenue Deficiencies:

In May 2004, Wisconsin Electric filed an application with the PSCW for an increase in electric and steam rates for anticipated 2005 revenue deficiencies associated with (1) costs for the new PWGS and the Oak Creek expansion being constructed as part of our PTF strategy, (2) costs associated with our energy efficiency procurement plan and (3) costs associated with making changes to our steam utility systems as part of the construction of the Marquette Interchange highway project in downtown Milwaukee, Wisconsin. The filing identified anticipated revenue deficiencies in 2005 attributable to Wisconsin in the amount of $84.8 million (4.5%) for the electric operations of Wisconsin Electric and $0.5 million (3.6%) for Wisconsin Electric's steam operations. In January 2005, as a result of the litigation involving our Oak Creek expansion, we amended this filing to reduce the total revenue request to $52.4 million. In May 2005, the PSCW issued its final written order implementing an annualized increase in electric rates of $59.7 million (3.1%) and an increase of $0.5 million (3.6%) in steam rates.

Other Utility Rate Matters

Electric Transmission Cost Recovery:

Wisconsin Electric divested its transmission assets with the formation of ATC in January 2001. We now procure transmission service from ATC at FERC approved tariff rates. In connection with the formation of ATC, our transmission costs have escalated due to the socialization of costs within ATC and increased transmission infrastructure requirements in the state. In 2002, in connection with the increased costs experienced by our customers, the PSCW issued an order which allowed us to use escrow accounting whereby we defer transmission costs that exceed amounts embedded in our rates. We are allowed to earn a return on the unrecovered transmission costs at our weighted average cost of capital. As of December 31, 2007, we have deferred $240.9 million of unrecovered transmission costs. The January 2008 rate order provided for the recovery of these costs over six years; and the escrow accounting treatment has been discontinued.

Fuel Cost Adjustment Procedure:

Within the State of Wisconsin, Wisconsin Electric operates under a fuel cost adjustment clause for fuel and purchased power costs associated with the generation and delivery of electricity and purchase power contracts. Embedded within its base rates is an amount to recover fuel costs. Under the current fuel rules, no adjustments are made to rates as long as fuel and purchased power costs are expected to be within a band of the costs embedded in current rates for the twelve month period ending December 31. If, however, annual fuel costs are expected to fall outside of the band, and actual costs fall outside of established fuel bands, then we may file for a change in fuel recoveries on a prospective basis. For 2008, the band is plus or minus 2%.

In June 2006, the PSCW opened a docket (01-AC-224) in which it was looking into revising the current fuel rules (Chapter PSC 116). In February 2007, five Wisconsin utilities regulated by the fuel rules, including Wisconsin Electric, filed a joint proposal to modify the existing rules in this docket. The proposal recommends modifying the rules to allow for escrow accounting for fuel costs outside a plus or minus 1% annual band of fuel costs allowed in rates. It further recommends that the escrow balance be trued-up annually following the end of each calendar year. We are unable to predict if or when the PSCW will make any changes to the existing fuel rules.

Edison Sault and Wisconsin Electric's operations in Michigan operate under a Power Supply Cost Recovery mechanism which generally allows for the recovery of fuel and purchase power costs on a dollar for dollar basis.

Gas Cost Recovery Mechanism:

Our natural gas operations operate under a GCRM as approved by the PSCW. Generally, the GCRM allows for a dollar for dollar recovery of gas costs. There is an incentive mechanism under the GCRM which allows for increased revenues if we acquire gas lower than benchmarks approved by the PSCW. During 2007, 2006 and 2005, no additional revenues were earned under the incentive portion of the GCRM.

Bad Debt Costs:

In January 2006, the PSCW issued an order approving the amortization over the next five years of bad debts deferred in 2004 for our gas operations. The bad debts deferred in 2004 related to electric operations will be considered for recovery in future rates, subject to audit and approval of the PSCW.

In February 2005, the PSCW approved our use of escrow accounting for residential bad debt costs. The final decision was received in March 2005. The escrow method of accounting for bad debt costs allows for deferral of Wisconsin residential bad debt expense that exceeds amounts allowed in rates. As a result of this approval from the PSCW, which extends through March 2009, we escrowed approximately $8.9 million, $3.7 million and $17.2 million in 2007, 2006 and 2005, respectively, related to bad debt costs. The January 2008 rate order allowed for the continued use of escrow accounting.

MISO Energy Markets:

In January 2005, we requested deferral accounting treatment from the PSCW for certain incremental costs or benefits that may occur due to the implementation on April 1, 2005 of the MISO Energy Markets. We received approval for this accounting treatment in March 2005. Additionally, in March 2005 we submitted a joint proposal to the PSCW with other utilities requesting escrow accounting treatment for the MISO Energy Markets costs until each utility's first rate case following April 1, 2008. The purpose of the March 2005 request for escrow accounting was to provide clarification on costs not included in the March 2005 approval for deferral accounting treatment. The PSCW approved deferral treatment for these costs in June 2006. In August 2007, the PSCW issued an order that adjusted the deferral treatment for certain MISO costs and determined that deferral accounting would end December 31, 2007. For additional information, see Industry Restructuring and Competition -- Electric Transmission and Energy Markets -- MISO.

Coal Generation Forced Outage - 2007:

In March 2007, we requested and received approval from the PSCW to defer as a regulatory asset approximately $13.2 million related to replacement power costs due to a forced outage of Unit 1 at the Pleasant Prairie Power Plant. The outage extended from February 2007 through March 2007. These costs will be recovered as part of the 2008 rate order.

Wholesale Electric Rates:

In August 2006, Wisconsin Electric filed a wholesale rate case with FERC. The filing requested an annual increase in rates of approximately $16.7 million applicable to four existing wholesale electric customers. This includes a mechanism for fuel and other cost adjustments. In November 2006, FERC accepted the rate filing subject to refund with interest. Three of the existing customers' rates were effective in January 2007. The remaining wholesale customer's rates were effective in May 2007. FERC approved a settlement of the rate filing in September 2007.

Depreciation Rates:

In January 2005, Wisconsin Electric and Wisconsin Gas filed a joint application with the PSCW for certification of depreciation rates for specific classes of utility plant assets. In November 2005, we received notice from the PSCW that the proposed estimated lives, net salvage values and depreciation rates were approved and became effective January 1, 2006. For more information, see Note A -- Summary of Significant Accounting Policies in the Notes to Consolidated Financial Statements.

Renewables, Efficiency and Conservation:

In March 2006, Wisconsin enacted new public benefits legislation, Act 141, which changes the renewable energy requirements for utilities. Act 141 requires Wisconsin utilities to provide 2% more of their total retail energy from renewable resources than their current levels by 2010, and 6% more renewable energy than their current levels by 2015. Act 141 establishes a statewide goal that 10% of all electricity in Wisconsin be generated by renewable resources by December 31, 2015. Assuming the bulk of additional renewables is wind turbines, Wisconsin Electric must obtain approximately 210 MW of additional renewable capacity by 2010 and another approximately 610 MW of additional renewable capacity by 2015 to meet the retail energy delivered requirements. We have already started development of additional sources of renewable energy to comply with commitments made as part of our PTF initiative which will assist us in complying with Act 141. See Wind Generation discussion below.

Act 141 allows the PSCW to delay a utility's implementation of the renewable portfolio standard if it finds that achieving the renewable requirement would be too expensive or would lessen reliability, or that new renewable projects could not be permitted on a timely basis or could not be served by adequate transmission facilities. The previous law did not include similar provisions. Act 141 provides that if a utility is in compliance with the renewable energy and energy efficiency requirements as determined by the PSCW, then the utility is considered in compliance with the Energy Priorities law. Prior to Act 141, there had been no agreement on how to determine compliance with the Energy Priorities law, which provides that it is the policy of the PSCW, to the extent it is cost-effective and technically feasible, to consider the following options in the listed order when reviewing energy-related applications: (1) energy conservation and efficiency, (2) noncombustible renewable energy resources, (3) combustible renewable energy resources, (4) natural gas, (5) oil or low sulfur coal and (6) high sulfur coal and other carbon-based fuels.

We continue to implement the requirements of Act 141. The PSCW has completed two rule-making proceedings required by the law. These proceedings dealt with renewable energy credits and conditions for utility and business voluntary participation in providing energy efficiency programs. Effective July 1, 2007, we began to pay the required 1.2% charge to support energy efficiency, conservation and renewable programs in Wisconsin as required by Act 141.

Wind Generation:

In June 2005, we purchased the development rights to a wind farm project (Blue Sky Green Field) from Navitas Energy, Inc. After receiving the necessary approvals and permits we began construction in June 2007. Wind turbine components began arriving at the site during the fourth quarter of 2007. We estimate that the capital cost of the project, excluding AFUDC, will be approximately $300 million. We currently expect the wind turbines to be placed into service by the second quarter of 2008.

In addition, in October 2007 we provided notice to FPL Energy, a subsidiary of FPL, that we were exercising the option we received in connection with the sale of Point Beach to purchase all rights to a new wind farm site in central Wisconsin. Once the purchase is complete, we will proceed with securing approvals and permits for construction and operation, and we expect to install wind turbines with approximately 100 MW of generating capacity. We expect the wind turbines to be placed into service between late 2010 or 2011, subject to regulatory approvals and turbine availability.

ELECTRIC SYSTEM RELIABILITY

In response to customer demand for higher quality power required by modern equipment, we are evaluating and updating our electric distribution system. We are taking steps to reduce the likelihood of outages by upgrading substations and rebuilding lines to upgrade voltages and reliability. These improvements, along with better technology for analysis of our existing system, better resource management to speed restoration and improved customer communication, are near-term efforts to enhance our current electric distribution infrastructure. For the long-term, we have developed a distribution system asset management strategy that requires increased levels of automation of both substations and line equipment to consistently provide the level of reliability needed for a digital economy.

We had adequate capacity to meet all of our firm electric load obligations during 2007. All of our generating plants performed well during the warmest periods of the summer and all power purchase commitments under firm contract

were received. During this period, public appeals for conservation were not required and we did not interrupt or curtail service to non-firm customers who participate in load management programs.

We expect to have adequate capacity to meet all of our firm load obligations during 2008. However, extremely hot weather, unexpected equipment failure or unavailability could require us to call upon load management procedures during 2008 as we have in past years.

ENVIRONMENTAL MATTERS

Consistent with other companies in the energy industry, we face significant ongoing environmental compliance and remediation challenges related to current and past operations. Specific environmental issues affecting our utility and non-utility energy segments include but are not limited to (1) air emissions such as CO_2, SO_2, NO_x, small particulates and mercury, (2) disposal of combustion by-products such as fly ash and (3) remediation of former manufactured gas plant sites.

We are currently pursuing a proactive strategy to manage our environmental issues including (1) substituting new and cleaner generating facilities for older facilities as part of our PTF strategy, (2) developing additional sources of renewable electric energy supply, (3) reviewing water quality matters such as discharge limits and cooling water requirements, (4) adding emission control equipment to existing facilities to comply with new ambient air quality standards and federal clean air rules, (5) entering into agreements with the EPA to reduce emissions of SO_2 and NO_x by more than 65% by 2013, (6) evaluating and implementing improvements to our cooling water intake systems, (7) continuing the beneficial re-use of ash and other solid products from coal-fired generating units and (8) conducting the clean-up of former manufactured gas plant sites. The capital cost of implementing the EPA consent decree is estimated to be approximately $1 billion over the 10 years ending 2013. These costs are principally associated with the installation of air quality controls on Pleasant Prairie Units 1 and 2 and Oak Creek Units 5-8. In June 2007, we submitted an application to the PSCW requesting approval to construct environmental controls at Oak Creek Units 5-8 by 2012 as required by the Consent Decree. We estimate the cost of this project to be approximately $750 million. Through December 31, 2007, we have spent approximately $381.0 million associated with implementing the EPA agreement. For further information concerning the Consent Decree, see Note S -- Commitments and Contingencies in the Notes to Consolidated Financial Statements in this report.

National Ambient Air Quality Standards:

In 2000 and 2001, Michigan and Wisconsin finalized state rules implementing phased emission reductions required to meet the NAAQS for 1-hour ozone. In 2004, the EPA began implementing NAAQS for 8-hour ozone and $PM_{2.5}$. In December 2006, the EPA further revised the $PM_{2.5}$ standard, and in June 2007, the EPA announced its proposal to further lower the 8-hour ozone standard.

8-hour Ozone Standard:

In April 2004, the EPA designated 10 counties in Southeastern Wisconsin as non-attainment areas for the 8-hour ozone NAAQS. States were required to develop and submit State Implementation Plans to the EPA by June 2007 to demonstrate how they intend to comply with the 8-hour ozone NAAQS. The rule that applies to emissions from our power plants in the affected areas of Wisconsin has been adopted by the state. The required reductions will be accomplished through implementation of the CAIR. (See below for further information regarding CAIR.) We believe compliance with the NO_x emission reduction requirements under the agreement with the EPA will substantially mitigate costs to comply with the EPA's 8-hour ozone NAAQS. In June 2007, the EPA announced its proposal to further lower the 8-hour standard. Until this proposal becomes a final rule, we are unable to predict the impact on the operation of our existing coal-fired generation facilities.

$PM_{2.5}$

Standard: In December 2004, the EPA designated $PM_{2.5}$ non-attainment areas in the country. All counties in Wisconsin and all counties in the Upper Peninsula of Michigan were designated as in attainment with the standard. It is unknown at this time whether Wisconsin or Michigan will require additional emission reductions as part of state or regional implementation of the $PM_{2.5}$ standard and what impact those requirements would have on operation of our existing coal-fired generation facilities. In December 2006, a more restrictive federal standard became effective, which may place some counties into non-attainment status. This standard is currently being litigated. Until such time as the states develop rules and submit State Implementation Plans to the EPA to demonstrate how they intend to comply with the standard, we are unable to predict the impact of this more restrictive standard on the operation of our

existing coal-fired generation facilities or our new PTF generating units being leased by Wisconsin Electric including OC 1, OC 2 and PWGS.

Clean Air Interstate Rule:

The EPA issued the final CAIR regulation in March 2005 to facilitate the states in meeting the 8-hour ozone and $PM_{2.5}$ standards by addressing the regional transport of SO_2 and NO_x. CAIR requires NO_x and SO_2 emission reductions in two phases from electric generating units located in a 28-state region within the eastern United States. Wisconsin and Michigan are affected states under CAIR. The phase 1 compliance deadline is January 1, 2009 for NO_x and January 1, 2010 for SO_2, and the phase 2 compliance deadline is January 1, 2015 for both NO_x and SO_2. Overall, the CAIR is expected to result in a 70% reduction in SO_2 emissions and a 65% reduction in NO_x emissions from 2002 emission levels. The states were required to develop and submit implementation plans by no later than March 2007. A final CAIR rule has been adopted in Wisconsin and Michigan. We believe that compliance with the NO_x and SO_2 emission reductions requirements under the Consent Decree will substantially mitigate costs to comply with the CAIR rule.

Clean Air Mercury Rule:

The EPA issued the final CAMR in March 2005, following the agency's 2000 regulatory determination that utility mercury emissions should be regulated. CAMR would limit mercury emissions from new and existing coal-fired power plants, and cap utility mercury emission in two phases, applicable in 2010 and 2018. The caps would limit emissions at approximately 20% and ultimately 70% below today's utility mercury levels. Because the control technology is under development, it is difficult to estimate what the cost would be to comply with the CAMR requirements. We believe the range of possible expenditures could be approximately $50 million to $200 million. The construction Air Permit issued for the Oak Creek expansion is not impacted by CAMR.

The federal rule was challenged by a number of states including Wisconsin and Michigan. On February 8, 2008, the U.S. Court of Appeals for the District of Columbia Circuit vacated CAMR and sent the rule back to EPA for re-consideration. At this time, we cannot predict the timing or impact on our operations of a future federal rule.

In October 2004, the WDNR issued mercury emission control rules that affect electric utilities in Wisconsin. The Wisconsin rules explicitly recognize an underlying state statutory restriction that state regulations cannot be more stringent than those included in any federal program and require that the WDNR must adopt state rule changes within 18 months of publication of any federal rules. In March 2007, the WDNR proposed changes to this rule to include an implementation plan for CAMR, along with a proposal for more stringent state-only rules. WDNR did not take any final action on the March 2007 rule proposal. The 2004 state rule will continue to apply to our Wisconsin facilities, unless and until it is revised in the future. This rule requires mercury emission reductions from existing coal-fueled units in three phases, beginning with an emission cap in 2008, and followed by a 40% reduction requirement by 2010 and a 75% reduction requirement by 2015.

As of January 2008, the Michigan Department of Environmental Quality has also proposed a rule to both implement CAMR and impose state-only requirements for achieving 90% emission reductions in 2015. At this time, we cannot predict how the Michigan Department of Environmental Quality will proceed with their rule proposal and its impact on our operations. As part of a new technology demonstration which the company undertook in partnership with the DOE, technology for the control of mercury has been installed at Presque Isle Power Plant. We plan to continue the operation of that equipment beyond the test period. Until the Michigan rule is promulgated, it is not known if that equipment will be sufficient to comply with reductions that might be required under that rule.

Clean Air Visibility Rule:

The EPA issued the CAVR in June 2005 to address regional haze, or regionally-impaired visibility caused by multiple sources over a wide area. The rule defines BART requirements for electric generating units and how BART will be addressed in the 28 states subject to EPA's CAIR. Under CAVR, states are required to identify certain industrial facilities and power plants that affect visibility in the nation's 156 Class I protected areas. States are then required to determine the types of emission controls that those facilities must use to control their emissions. The pollutants from power plants that reduce visibility include particulate matter or compounds that contribute to fine particulate formation, NO_x, SO_2 and ammonia. States were required to submit plans to implement CAVR to the EPA by December 2007. The reductions associated with the state plans are scheduled to begin to take effect in 2014, with full implementation before 2018. Wisconsin is in the final phase of promulgating rules which cover one aspect of the regulations. We do not believe that these rules, if adopted in their current form, will have a material impact on our costs. Michigan has not yet issued a draft rule. Until the rules are final, we are unable to predict the impact on our system.

Clean Water Act:

Section 316(b) of the CWA requires that the location, design, construction and capacity of cooling water intake structures reflect the BTA for minimizing adverse environmental impact. This law dates back to 1972; however, prior to September 2004, there were no federal rules that defined precisely how states and EPA regions determined that an existing intake met BTA requirements. The Phase II rule established, for the first time, national performance standards and compliance alternatives for existing facilities that are designed to minimize the potential adverse environmental impacts to aquatic organisms associated with water withdrawals from cooling water intakes. Costs associated with implementation of the 316(b) rules for Wisconsin Electric's Oak Creek Power Plant, We Power's Oak Creek expansion and PWGS were included in project costs.

In January 2007, the Federal Court of Appeals for the Second Circuit issued a decision concerning the Phase II rule for existing facilities (Riverkeeper, Inc. v. EPA, Nos. 04-6692-ag(L) (2d Cir. 2007)). The Second Circuit found certain portions of the rule impermissible and remanded several parts of the Phase II rule to the EPA for further consideration or potential additional rulemaking. Consistent with its announcement in March, in July 2007, the EPA formally suspended the Phase II rule in its entirety and directed states to use their "best professional judgment" in evaluating intake systems. We will work with the relevant state agencies as permits for our facilities come due for renewal to determine what, if any, actions need to be taken. Until the EPA completes its reconsideration and rulemaking, we cannot predict what impact these changes to the federal rules may have on our facilities. For additional information on this matter related to the Oak Creek expansion, see Factors Affecting Results, Liquidity and Capital Resources -- *Power the Future* -- Oak Creek Expansion in this report.

Manufactured Gas Plant Sites:

We are voluntarily reviewing and addressing environmental conditions at a number of former manufactured gas plant sites. For further information, see Note S -- Commitments and Contingencies in the Notes to Consolidated Financial Statements.

Ash Landfill Sites:

We aggressively seek environmentally acceptable, beneficial uses for our combustion byproducts. For further information, see Note S -- Commitments and Contingencies in the Notes to Consolidated Financial Statements.

EPA Consent Decree:

In April 2003, Wisconsin Electric and the EPA announced that a Consent Decree had been reached that resolved all issues related to a request for information that had been issued by the EPA. The U.S. District Court for the Eastern District of Wisconsin approved the amended Consent Decree and entered it in October 2007. For further information, see Note S -- Commitments and Contingencies in the Notes to Consolidated Financial Statements.

Greenhouse Gases:

We continue to take voluntary measures to reduce our emissions of greenhouse gases. We support flexible, market-based strategies to curb greenhouse gas emissions, including emissions trading, joint implementation projects and credit for early actions. We support a voluntary approach that encourages technology development and transfer and includes all sectors of the economy and all significant global emitters.

Our emissions in future years will continue to be influenced by several actions completed, planned or underway, including:

- Repowering the Port Washington Power Plant from coal to natural gas - fired combined cycle units.
- Adding coal-fired units as part of the Oak Creek expansion that will be the most thermally efficient coal units in our system.
- Increasing investment in energy efficiency and conservation.
- Adding additional wind capacity and promoting increased participation in the Energy for Tomorrow® renewable energy program.

Federal, state, regional and international authorities have undertaken efforts to limit greenhouse gas emissions. Legislative proposals that would impose mandatory restrictions on CO_2 emissions continue to be considered in the U.S. Congress. Although the ultimate outcome of these efforts cannot be determined at this time, mandatory restrictions on our CO_2 emissions could result in significant compliance costs that could affect future results of operations, cash flows and financial condition. For additional information, see the caption "We may face significant costs to comply with the regulation of greenhouse gas emissions" under Item 1A Risk Factors in this report.

LEGAL MATTERS

Arbitration Proceedings:

Our largest electric customers, two iron ore mines, operate in the Upper Peninsula of Michigan. The mines represent approximately 6% of our annual electric sales; however, the earnings are insignificant to us. The mines had special negotiated contracts that expired in December 2007. The contracts had price caps for approximately 80% of the energy sales. We did not recognize revenue on amounts billed that exceeded the price caps.

The incremental power costs in the Upper Peninsula of Michigan are now determined by MISO. In April 2005, we began to bill the mines the incremental power costs as quantified by the MISO Energy Markets. The mines notified us that they were disputing these billings and a portion of these disputed amounts were deposited in escrow. In September 2005, the mines notified us that they filed for formal arbitration related to the contracts. We notified the mines that we believe that they failed to comply with certain notification provisions related to annual production as specified within the contracts.

In May 2007, Wisconsin Electric entered into a settlement agreement with the mines. The settlement was a full and complete resolution of all claims and disputes between the parties for electric service rendered by Wisconsin Electric under the power purchase agreements through March 31, 2007. Pursuant to the settlement, the mines paid Wisconsin Electric approximately $9.0 million and Wisconsin Electric released to the mines all funds held in escrow. The estimated earnings impact of the payment from the mines was $0.04 per share. The settlement also provided a mutually satisfactory pricing structure through the power purchase agreement expiration date of December 31, 2007. Beginning January 1, 2008, the mines became eligible to receive electric service from Wisconsin Electric in accordance with tariffs approved by the MPSC.

Stray Voltage:

On July 11, 1996, the PSCW issued a final order regarding the stray voltage policies of Wisconsin's investor-owned utilities. The order clarified the definition of stray voltage, affirmed the level at which utility action is required, and placed some of the responsibility for this issue in the hands of the customer. Additionally, the order established a uniform stray voltage tariff which delineates utility responsibility and provides for the recovery of costs associated with unnecessary customer demanded services.

In recent years, dairy farmers have commenced actions or made claims against Wisconsin Electric for loss of milk production and other damages to livestock allegedly caused by stray voltage, and, more recently, ground currents resulting from the operation of its electrical system, even though that electrical system has been operated within the parameters of the PSCW's order. The Wisconsin Supreme Court has rejected the arguments that, if a utility company's measurement of stray voltage is below the PSCW "level of concern," that utility could not be found negligent in stray voltage cases. Additionally, the Court has held that the PSCW regulations regarding stray voltage were only minimum standards to be considered by a jury in stray voltage litigation. As a result of this case, claims by dairy farmers for livestock damage have been based upon ground currents with levels measuring less than the PSCW "level of concern."

In May 2005, a stray voltage lawsuit was filed against Wisconsin Electric. This lawsuit was settled in June 2007 and such settlement did not have a material adverse effect on our financial condition or results of operations. Although we do not have any open stray voltage cases at this time, we continue to evaluate various options and strategies to mitigate this risk.

NUCLEAR OPERATIONS

Point Beach Nuclear Plant:

Wisconsin Electric previously owned two electric generating units (Unit 1 and Unit 2) at Point Beach in Two Rivers, Wisconsin. During 2007, 2006 and 2005, Point Beach provided approximately 17.3%, 25.3% and 20.0%, respectively, of Wisconsin Electric's net electric energy supply.

On September 28, 2007, Wisconsin Electric sold Point Beach to an affiliate of FPL for approximately $924 million. Pursuant to the terms of the sale agreement, the buyer purchased Point Beach, its nuclear fuel, associated inventories and assumed the obligation to decommission the plant. Wisconsin Electric retained approximately $506 million of the sales proceeds, which represents the net book value of the assets sold and certain transaction costs. In addition,

Wisconsin Electric has deferred the net gain on the sale of approximately $418 million as a regulatory liability and has deposited those proceeds into a restricted cash account.

In connection with the sale, Wisconsin Electric also transferred $390 million of decommissioning funds to the buyer. Wisconsin Electric then liquidated the balance of the decommissioning trust assets and retained approximately $552 million, which was also placed into the restricted cash account. We intend to use the cash in the restricted cash account and the interest earned on the balance for the benefit of our customers and to pay certain taxes. Our regulators are directing the manner in which these proceeds will benefit customers. For further information on the 2008 rate case, see Factors Affecting Results, Liquidity and Capital Resources - Utility Rates and Regulatory Matters in this report.

A long-term power purchase agreement with the buyer became effective upon closing of the sale. Pursuant to this agreement, Wisconsin Electric is purchasing all of the energy produced by Point Beach. The power purchase agreement extends through 2030 for Unit 1 and 2033 for Unit 2. Based on the agreement, we are paying a pre-determined price per MWh for energy delivered according to a schedule that is established in the agreement. Under the agreement, if our credit rating and the credit rating of Wisconsin Electric from either S&P or Moody's fall below investment grade, or if the holders of any indebtedness in excess of $100.0 million accelerate or have the right to accelerate the maturity of such indebtedness as a result of a default, we would need to provide collateral in the amount of $100.0 million (escalating at 3% per year commencing in 2024).

Used Nuclear Fuel Storage and Disposal:

During Wisconsin Electric's ownership of Point Beach, Wisconsin Electric was authorized by the PSCW to load and store sufficient dry fuel storage containers to allow Point Beach Units 1 and 2 to operate to the end of their original operating licenses, but not to exceed the original 48-canister capacity of the dry fuel storage facility. The original operating licenses were set to expire in October 2010 for Unit 1 and in March 2013 for Unit 2 before they were renewed and extended by the NRC in December 2005.

Temporary storage alternatives at Point Beach are necessary until the DOE takes ownership of and permanently removes the used fuel as mandated by the Nuclear Waste Policy Act of 1982, as amended in 1987. The Nuclear Waste Policy Act established the Nuclear Waste Fund which is composed of payments made by the generators and owners of such waste and fuel. Effective January 31, 1998, the DOE failed to meet its contractual obligation to begin removing used fuel from Point Beach, a responsibility for which Wisconsin Electric paid a total of $215.2 million into the Nuclear Waste Fund over the life of its ownership of Point Beach.

On August 13, 2000, the United States Court of Appeals for the Federal Circuit ruled in a lawsuit brought by Maine Yankee and Northern States Power Company that the DOE's failure to begin performance by January 31, 1998 constituted a breach of the Standard Contract, providing clear grounds for filing complaints in the Court of Federal Claims. Consequently, Wisconsin Electric filed a complaint on November 16, 2000 against the DOE in the Court of Federal Claims. In October 2004, the Court of Federal Claims granted Wisconsin Electric's motion for summary judgment on liability. The Court held a trial during September and October 2007 to determine damages. We anticipate a decision by the end of 2008 or during 2009. Wisconsin Electric incurred substantial damages prior to the sale of Point Beach and we are seeking recovery of our damages in this lawsuit and we expect that any recoveries would be considered in setting future rates.

INDUSTRY RESTRUCTURING AND COMPETITION

Electric Utility Industry

The regulated energy industry continues to experience significant changes. FERC continues to support large RTOs, which will affect the structure of the wholesale market. To this end, the MISO implemented a bid-based market, the MISO Energy Markets, including the use of LMP to value electric transmission congestion and losses. The MISO Energy Markets commenced operation on April 1, 2005. Increased competition in the retail and wholesale markets, which may result from restructuring efforts, could have a significant and adverse financial impact on us. It is uncertain when retail access might be implemented in Wisconsin; however, Michigan has adopted retail choice which potentially affects our Michigan operations. In August 2005, President Bush signed into law the Energy Policy Act, which impacts the electric utility industry. (See Other Matters below for additional information on the Energy Policy Act). In addition, major issues in industry restructuring, implementation of RTO markets and market

power mitigation received substantial attention in 2006 and prior years. We continue to focus on infrastructure issues through our PTF growth strategy.

Restructuring in Wisconsin:

Electric utility revenues in Wisconsin are regulated by the PSCW. Due to many factors, including relatively competitive electric rates charged by the state's electric utilities, the PSCW has been focused in recent years on electric reliability infrastructure issues for the State of Wisconsin. These issues include:

- Addition of new generating capacity in the state;
- Modifications to the regulatory process to facilitate development of merchant generating plants;
- Development of a regional independent electric transmission system operator;
- Improvements to existing and addition of new electric transmission lines in the state; and
- Addition of renewable generation.

The PSCW continues to maintain the position that the question of whether to implement electric retail competition in Wisconsin should ultimately be decided by the Wisconsin legislature. No such legislation has been introduced in Wisconsin to date.

Restructuring in Michigan:

As of January 1, 2002, our Michigan retail customers were allowed to remain with their regulated utility at regulated rates or choose an alternative electric supplier to provide power supply service. We have maintained our generation capacity and distribution assets and provide regulated service as we have in the past. We continue providing distribution and customer service functions regardless of the customer's power supplier.

Competition and customer switching to alternative suppliers in our service territories in Michigan has been limited. With the exception of two general inquiries, no alternate supplier activity has occurred in our service territories in Michigan. We believe that this lack of alternate supplier activity reflects our small market area in Michigan, our competitive regulated power supply prices and a general lack of interest in the Upper Peninsula of Michigan as a market for alternative electric suppliers.

Electric Transmission and Energy Markets

ATC:

ATC is regulated by FERC for all rate terms and conditions of service and is a transmission-owning member of MISO. As of February 1, 2002, operational control of ATC's transmission system was transferred to MISO, and Wisconsin Electric and Edison Sault became non-transmission owning members and customers of MISO.

MISO:

In connection with its status as a FERC approved RTO, MISO implemented a bid-based energy market, the MISO Energy Markets, which commenced operations on April 1, 2005. As part of this energy market, MISO developed a market-based platform for valuing transmission congestion and losses premised upon the LMP system that has been implemented in certain northeastern and mid-Atlantic states. The LMP system includes the ability to mitigate or eliminate congestion costs through FTRs. FTRs are allocated to market participants by MISO. A new allocation of FTRs was completed for the period of June 1, 2007 through May 31, 2008. We were granted substantially all of the FTRs that we were permitted to request during the allocation process. Previously, our unhedged congestion costs had not been explicitly identified and were embedded in our fuel and purchased power expenses. The congestion charges are deferred as approved by the PSCW, and we expect to recover the costs in current rates, subject to review and approval by the PSCW.

In MISO, base transmission costs are currently being paid by LSEs located in the service territories of each MISO transmission owner. On February 1, 2008, FERC issued several orders confirming that the current transmission cost allocation methodology is just and reasonable and should continue in the future. These orders are subject to rehearings or appeals.

In April 2006, FERC issued an order determining that MISO had not applied its energy markets tariff correctly in the assessment of RSG charges. FERC ordered MISO to resettle all affected transactions retroactive to April 1, 2005. In October 2006 and March 2007, we received additional rulings from FERC on these issues. FERC's rulings have been challenged by MISO and numerous other market participants. MISO commenced with the resettlement of the market in accordance with the orders in July 2007. The resettlement was completed in

January 2008 and resulted in a net cost increase of $7.8 million. Several entities filed formal complaints with FERC on the assessment of these charges. We filed in support of these complaints.

In November 2007, FERC issued another RSG Order related to the rehearing requests previously filed. This Order provided a clarification that is contrary to how MISO has been implementing the resettlements. Once again, several parties, including Wisconsin Electric, filed for rehearing or clarification.

In addition, FERC ruled on the formal complaints filed by other entities in August 2007. FERC ruled that the current RSG cost allocation methodology may be unjust and unreasonable and established a refund effective date of August 10, 2007. MISO has been ordered to file a new cost allocation methodology by March 2008. At this time, we are unable to determine the resulting financial impact associated with this proceeding.

MISO is in the process of developing a market for two ancillary services, regulation reserves and contingency reserves. In February 2007, MISO filed tariff revisions to include ancillary services. The MISO ancillary services market is expected to begin in June 2008. We currently self-provide both regulation reserves and contingency reserves. In the MISO ancillary services market, we expect that we will buy/sell regulation and contingency reserves from/to the market. The MISO ancillary services market is expected to reduce overall ancillary services costs in the MISO footprint. The MISO ancillary services market is also expected to enable MISO to assume significant balancing area responsibilities such as frequency control and disturbance control

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Natural Gas Utility Industry

Restructuring in Wisconsin:

The PSCW previously instituted generic proceedings to consider how its regulation of gas distribution utilities should change to reflect the changing competitive environment in the natural gas industry. To date, the PSCW has made a policy decision to deregulate the sale of natural gas in customer segments with workably competitive market choices and has adopted standards for transactions between a utility and its gas marketing affiliates. However, work on deregulation of the gas distribution industry by the PSCW is presently on hold. Currently, we are unable to predict the impact of potential future deregulation on our results of operations or financial position.

OTHER MATTERS

Energy Policy Act:

In August 2005, President Bush signed into law the Energy Policy Act. Among other things, the Energy Policy Act includes tax subsidies for electric utilities and the repeal of PUHCA 1935. The Energy Policy Act also amends federal energy laws and provides FERC with new oversight responsibilities for the electric utility industry. Implementation of the Energy Policy Act requires the development of regulations by federal agencies, including FERC. As noted above, the Energy Policy Act and corresponding rules required us to seek FERC authorization to allow Wisconsin Electric to lease from We Power the three PTF units that are currently being constructed by We Power. We received approval of these leases from FERC in December 2006. Additionally, the Energy Policy Act repealed PUHCA 1935 and enacted PUHCA 2005, transferring jurisdiction over holding companies from the SEC to FERC. Wisconsin Energy and Wisconsin Electric were exempt holding companies under PUHCA 1935, and, accordingly, were exempt from that law's provisions other than with respect to certain acquisitions of securities of a public utility. In March 2006, Wisconsin Energy and Wisconsin Electric each filed with FERC notification of its status as a holding company as required under FERC regulations implementing PUHCA 2005 and a request for exempt status similar to that held under PUHCA 1935. In June 2006, Wisconsin Energy and Wisconsin Electric received notice from FERC confirming their status as holding companies as required under FERC regulations implementing PUHCA 2005 and granting exempt status similar to that held under PUHCA 1935. As federal agencies continue to develop new rules to implement the Energy Policy Act, we expect additional impacts on Wisconsin Energy and its subsidiaries in the future.

Guardian:

In April 2006, we sold our one-third interest in Guardian to an affiliate of Northern Border Partners, L.P. for approximately $38.5 million. The sale generated an after-tax gain of approximately $1.7 million. Guardian owns an interstate natural gas pipeline from the Joliet, Illinois market hub to southeastern Wisconsin that is designed to serve the growing demand for natural gas in Wisconsin and Northern Illinois. Guardian Pipeline began commercial operation in early December 2002. We have committed to purchase 650,000 Dth (approximately

87% of the pipeline's total capacity) per day of capacity on the pipeline over a long-term contract that expires in December 2022.

ACCOUNTING DEVELOPMENTS

New Pronouncements:

See Note B -- Recent Accounting Pronouncements in the Notes to Consolidated Financial Statements in this report for information on new accounting pronouncements.

CRITICAL ACCOUNTING ESTIMATES

Preparation of financial statements and related disclosures in compliance with GAAP requires the application of appropriate technical accounting rules and guidance, as well as the use of estimates. The application of these policies necessarily involves judgments regarding future events, including the likelihood of success of particular projects, legal and regulatory challenges and anticipated recovery of costs. These judgments, in and of themselves, could materially impact the financial statements and disclosures based on varying assumptions. In addition, the financial and operating environment may also have a significant effect, not only on the operation of our business, but on our results reported through the application of accounting measures used in preparing the financial statements and related disclosures, even if the nature of the accounting policies applied have not changed.

The following is a list of accounting policies that are most significant to the portrayal of our financial condition and results of operations and that require management's most difficult, subjective or complex judgments:

Regulatory Accounting:

Our utility subsidiaries operate under rates established by state and federal regulatory commissions which are designed to recover the cost of service and provide a reasonable return to investors. Under SFAS 71, the actions of our regulators may allow us to defer costs that non-regulated entities would expense. The actions of our regulators may also require us to accrue liabilities that non-regulated companies would not. As of December 31, 2007, we had $1,126.3 million in regulatory assets and $1,877.4 million in regulatory liabilities. In the future, if we move to market based rates, or if the actions of our regulators change, we may conclude that we are unable to follow SFAS 71. In this situation, continued deferral of certain regulatory asset and liability amounts on the utilities' books, as allowed under SFAS 71, may no longer be appropriate and the unamortized regulatory assets net of the regulatory liabilities would be recorded as an extraordinary after-tax non-cash charge to earnings. We continually review the applicability of SFAS 71 and have determined that it is currently appropriate to continue following SFAS 71. In addition, each quarter we perform a review of our regulatory assets and our regulatory environment and we evaluate whether we believe that it is probable that we will recover the regulatory assets in future rates. See Note C -- Regulatory Assets and Liabilities in the Notes to Consolidated Financial Statements for additional information.

Pension and OPEB:

Our reported costs of providing non-contributory defined pension benefits (described in Note O -- Benefits in the Notes to Consolidated Financial Statements) are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience. Pension costs are impacted by actual employee demographics (including age, compensation levels and employment periods), the level of contributions made to plans and earnings on plan assets. Changes made to the provisions of the plans may also impact current and future pension costs. Pension costs may also be significantly affected by changes in key actuarial assumptions, including anticipated rates of return on plan assets and the discount rates used in determining the projected benefit obligation and pension costs.

In accordance with SFAS 87 and SFAS 158, changes in pension obligations associated with these factors may not be immediately recognized as pension costs on the income statement, but generally are recognized in future years over the remaining average service period of plan participants. As such, significant portions of pension costs recorded in any period may not reflect the actual level of cash benefits provided to plan participants.

The following chart reflects pension plan sensitivities associated with changes in certain actuarial assumptions by the indicated percentage. Each sensitivity reflects a change to the given assumption, holding all other assumptions constant:

Pension Plan Actuarial Assumption	Impact on Annual Cost
	(Millions of Dollars)
0.5% decrease in discount rate and lump sum conversion rate	$5.7
0.5% decrease in expected rate of return on plan assets	$5.3

In addition to pension plans, we maintain OPEB plans which provide health and life insurance benefits for retired employees (described in Note O -- Benefits in the Notes to Consolidated Financial Statements). We account for these plans in accordance with SFAS 106. Our reported costs of providing these post-retirement benefits are dependent upon numerous factors resulting from actual plan experience including employee demographics (age and compensation levels), our contributions to the plans, earnings on plan assets and health care cost trends. Changes made to the provisions of the plans may also impact current and future OPEB costs. OPEB costs may also be significantly affected by changes in key actuarial assumptions, including anticipated rates of return on plan assets and the discount rates used in determining the OPEB and post-retirement costs. Our OPEB plan assets are primarily made up of equity and fixed income investments. Fluctuations in actual equity market returns, as well as changes in general interest rates, may result in increased or decreased other post-retirement costs in future periods. Similar to accounting for pension plans, the regulators of our utility segment have adopted SFAS 106 for rate making purposes.

The following chart reflects OPEB plan sensitivities associated with changes in certain actuarial assumptions by the indicated percentage. Each sensitivity reflects a change to the given assumption, holding all other assumptions constant:

OPEB Plans Actuarial Assumption	Impact on Reported Annual Cost
	(Millions of Dollars)
0.5% decrease in discount rate	$2.1
0.5% decrease in health care cost trend rate in all future years	($2.6)
0.5% decrease in expected rate of return on plan assets	$1.0

Unbilled Revenues:

We record utility operating revenues when energy is delivered to our customers. However, the determination of energy sales to individual customers is based upon the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of their last meter reading are estimated and corresponding unbilled revenues are calculated. This unbilled revenue is estimated each month based upon actual generation and throughput volumes, recorded sales, estimated customer usage by class, weather factors, estimated line losses and applicable customer rates. Significant fluctuations in energy demand for the unbilled period or changes in the composition of customer classes could impact the accuracy of the unbilled revenue estimate. Total utility operating revenues during 2007 of approximately $4.2 billion included accrued utility revenues of $312.2 million as of December 31, 2007.

Deferred Tax Assets Valuation Allowance:

We record deferred tax asset valuation allowances in accordance with SFAS 109. As of December 31, 2007 and 2006, we had recorded $3.3 million and $3.4 million of valuation allowances primarily related to uncertainty of our ability to benefit from state loss carryforwards in the future. In June 2005, we re-evaluated our state loss carryforwards in conjunction with our new PTF plants and concluded that it was more likely than not that we will be able to utilize certain tax benefits associated with state net operating losses that had been carried forward from prior years. As such, in 2006 and 2005 we reversed $5.8 million and $16.3 million of valuation allowances associated with the state tax net operating losses that have been carried forward to future years. The remaining state loss carryforwards begin to expire in 2008 and have been reduced by a valuation allowance.

If we would conclude in a future period that it was more likely than not that some or all of the remaining state NOLs would be realized before expiration, GAAP would require that we reverse the related valuation allowance in that

period. Any change to the allowance, as a result of a change in judgment about the realization of deferred tax assets, is reported as an increase or decrease in income.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See Factors Affecting Results, Liquidity and Capital Resources -- Market Risks and Other Significant Risks in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations in this report for information concerning potential market risks to which Wisconsin Energy and its subsidiaries are exposed.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

WISCONSIN ENERGY CORPORATION

CONSOLIDATED INCOME STATEMENTS

Year Ended December 31

	2007	2006	2005
	(Millions of Dollars, Except Per Share Amounts)		
Operating Revenues	$ 4,237.8	$ 3,996.4	$ 3,815.5
Operating Expenses			
Fuel and purchased power	996.4	802.0	776.7
Cost of gas sold	1,052.7	1,018.3	1,047.3
Other operation and maintenance	1,135.3	1,183.7	1,007.9
Depreciation, decommissioning and amortization	328.2	326.4	332.0
Property and revenue taxes	103.2	97.5	88.7
Amortization of gain	(6.5)	-	-
Total Operating Expenses	3,609.3	3,427.9	3,252.6
Operating Income	628.5	568.5	562.9
Equity in Earnings of Transmission Affiliate	43.1	38.6	34.6
Other Income and Deductions, net	48.9	53.1	28.7
Interest Expense, net	167.6	172.7	173.4
Income from Continuing Operations Before Income Taxes	552.9	487.5	452.8
Income Taxes	216.4	175.0	149.2
Income from Continuing Operations	336.5	312.5	303.6
Income (loss) from Discontinued Operations, Net of Tax	(0.9)	3.9	5.1

Net Income	$ 335.6	$ 316.4	$ 308.7
Earnings Per Share (Basic)			
Continuing Operations	$ 2.88	$ 2.67	$ 2.59
Discontinued Operations	(0.01)	0.03	0.05
Total Earnings Per Share (Basic)	$ 2.87	$ 2.70	$ 2.64
Earnings Per Share (Diluted)			
Continuing Operations	$ 2.84	$ 2.64	$ 2.56
Discontinued Operations	(0.01)	0.03	0.05
Total Earnings Per Share (Diluted)	$ 2.83	$ 2.67	$ 2.61
Weighted Average Common Shares Outstanding (Millions)			
Basic	116.9	117.0	117.0
Diluted	118.5	118.4	118.4

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

WISCONSIN ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

December 31

ASSETS

	2007	2006
	(Millions of Dollars)	
Property, Plant and Equipment		
In service	$ 8,959.1	$ 9,265.4
Accumulated depreciation	(3,123.9)	(3,423.7)
	5,835.2	5,841.7
Construction work in progress	1,764.1	992.4
Leased facilities, net	81.9	87.5
Nuclear fuel, net	-	130.9

Net Property, Plant and Equipment	7,681.2	7,052.5
Investments		
Nuclear decommissioning trust fund	-	881.6
Restricted cash	323.5	-
Equity investment in transmission affiliate	238.5	228.5
Other	42.7	54.7
Total Investments	604.7	1,164.8
Current Assets		
Cash and cash equivalents	27.4	37.0
Restricted cash	408.1	-
Accounts receivable, net of allowance for doubtful accounts of $38.0 and $35.1	361.8	379.3
Accrued revenues	312.2	257.8
Materials, supplies and inventories	361.3	417.2
Regulatory assets	164.7	16.9
Prepayments and other	214.2	136.7
Total Current Assets	1,849.7	1,244.9
Deferred Charges and Other Assets		
Regulatory assets	961.6	1,074.0
Goodwill, net	441.9	441.9
Other	181.2	152.1
Total Deferred Charges and Other Assets	1,584.7	1,668.0
Total Assets	$ 11,720.3	$ 11,130.2

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

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WISCONSIN ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

December 31

CAPITALIZATION AND LIABILITIES

	2007	2006
	(Millions of Dollars)	
Capitalization		
Common equity	$ 3,099.2	$ 2,889.0
Preferred stock of subsidiary	30.4	30.4
Long-term debt	3,172.5	3,073.4
Total Capitalization	6,302.1	5,992.8
Current Liabilities		
Long-term debt due currently	352.8	296.7
Short-term debt	900.7	911.9
Accounts payable	478.3	404.5
Regulatory liabilities	563.1	4.5
Other	207.9	274.9
Total Current Liabilities	2,502.8	1,892.5
Deferred Credits and Other Liabilities		
Regulatory liabilities	1,314.3	1,467.6
Asset retirement obligations	54.5	371.7
Deferred income taxes - long-term	551.7	572.9
Accumulated deferred investment tax credits	47.8	52.0
Deferred revenue, net	347.7	186.2
Pension and other benefit obligations	310.1	363.9
Other long-term liabilities	289.3	230.6
Total Deferred Credits and Other Liabilities	2,915.4	3,244.9
Commitments and Contingencies (Note S)		
Total Capitalization and Liabilities	$ 11,720.3	$ 11,130.2

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

WISCONSIN ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

		Year Ended December 31		
		2007	2006	2005
			(Millions of Dollars)	
Operating Activities				
Net income		$ 335.6	$ 316.4	$ 308.7
Reconciliation to cash				
Depreciation, decommissioning and amortization		338.0	336.8	350.0
Nuclear fuel expense amortization		23.2	28.7	23.0
Equity in earnings of transmission affiliate		(43.1)	(38.6)	(34.6)
Distributions from transmission affiliate		33.2	30.4	27.0
Deferred income taxes and investment tax credits, net		20.4	(54.0)	63.4
Deferred revenue		164.5	80.3	54.7
Change in -	Accounts receivable and accrued revenues	(36.9)	61.2	(124.6)
	Inventories	31.3	34.4	(48.5)
	Other current assets	(5.4)	(26.5)	6.5
	Accounts payable	10.1	(36.3)	93.4
	Accrued income taxes, net	(106.9)	50.2	6.1
	Deferred costs, net	(56.3)	(29.1)	(132.6)
	Other current liabilities and other	(175.2)	(23.9)	(13.5)
Cash Provided by Operating Activities		532.5	730.0	579.0
Investing Activities				
Capital expenditures		(1,211.5)	(928.7)	(745.1)
Investment in transmission affiliate		-	(14.6)	(10.5)
Proceeds from asset sales, net		963.1	102.4	133.8
Proceeds from liquidation of nuclear decommissioning trust		552.4	-	-
Cash designated as restricted cash		(731.6)	-	-
Nuclear fuel		(23.8)	(47.7)	(49.7)
Nuclear decommissioning funding		(11.7)	(17.6)	(17.6)
Proceeds from investments within nuclear decommissioning trust		1,528.7	530.7	435.7
Other activity within nuclear decommissioning trust		(1,528.7)	(530.7)	(435.7)
Other		(80.1)	(33.3)	(10.1)
Cash (Used in) Investing Activities		(543.2)	(939.5)	(699.2)
Financing Activities				
Exercise of stock options		36.1	26.8	47.0
Purchase of common stock		(67.8)	(48.0)	(75.1)

Dividends paid on common stock	(116.9)	(107.6)	(102.9)
Issuance of long-term debt	523.4	337.9	285.8
Retirement of long-term debt	(363.8)	(493.8)	(112.2)
Change in short-term debt	(11.2)	455.6	118.3
Other, net	1.3	2.4	(3.1)
Cash Provided by Financing Activities	1.1	173.3	157.8
Change in Cash and Cash Equivalents	(9.6)	(36.2)	37.6
Cash and Cash Equivalents at Beginning of Year	37.0	73.2	35.6
Cash and Cash Equivalents at End of Year	$ 27.4	$ 37.0	$ 73.2
Supplemental Information - Cash Paid For			
Interest (net of amount capitalized)	$ 191.4	$ 183.4	$ 162.3
Income taxes (net of refunds)	$ 291.6	$ 154.2	$ 47.5

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

WISCONSIN ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF COMMON EQUITY

	Common Stock	Other Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Unearned Compensation	Stock Options Exercisable	Total
				(Millions of Dollars)			
Balance - December 31, 2004	$ 1.2	$ 785.1	$ 1,718.7	$ (7.4)	$ (7.6)	$ 2.4	$ 2,492.4
Net income			308.7				308.7
Other comprehensive income							
Minimum pension liability				(4.1)			(4.1)
	-	-	308.7	(4.1)	-	-	304.6

Comprehensive income							
Common stock cash							
dividends of $0.88 per share			(102.9)				(102.9)
Exercise of stock options		47.0					47.0
Purchase of common stock		(75.1)					(75.1)
Restricted stock and							
performance share awards		0.9			(1.5)		(0.6)
Amortization and forfeiture of							
performance shares and restricted stock		-			3.7		3.7
Tax benefit from exercise of stock options		11.1					11.1
Other		1.3				(1.4)	(0.1)
Balance - December 31, 2005	1.2	770.3	1,924.5	(11.5)	(5.4)	1.0	2,680.1
Net income			316.4				316.4
Other comprehensive income							
Minimum pension liability				2.5			2.5
Hedging, net				0.4			0.4
Comprehensive income	-	-	316.4	2.9	-	-	319.3
Common stock cash							
dividends of $0.92 per share			(107.6)				(107.6)
Exercise of stock options		26.8					26.8
Purchase of common stock		(48.0)					(48.0)
Tax benefit from exercise of stock		8.4					8.4

options							
Stock-based compensation and awards of restricted stock		9.8					9.8
Modification of performance share awards		(6.3)					(6.3)
Reclassification of unearned compensation to Other Paid In Capital upon the adoption of SFAS 123R -- Note J		(5.4)			5.4		-
Adoption of SFAS 158				7.0			7.0
Other		(0.1)				(0.4)	(0.5)
Balance - December 31, 2006 as originally reported	1.2	755.5	2,133.3	(1.6)	-	0.6	2,889.0
Cumulative effect of FIN 48. See Note H.			(0.3)				(0.3)
Balance - January 1, 2007 adoption of FIN 48	1.2	755.5	2,133.0	(1.6)	-	0.6	2,888.7
Net income			335.6				335.6
Other comprehensive income							
Hedging, net				0.3			0.3
Comprehensive income	-	-	335.6	0.3	-	-	335.9
Common stock cash dividends of $1.00 per share			(116.9)				(116.9)
Exercise of stock options		36.1					36.1
		(67.8)					(67.8)

Purchase of common stock							
Tax benefit from exercise of stock options		10.8					10.8
Stock-based compensation and awards of restricted stock		12.7					12.7
Other		0.2	(0.3)			(0.2)	(0.3)
Balance - December 31, 2007	$ 1.2	$ 747.5	$ 2,351.4	$ (1.3)	$ -	$ 0.4	$ 3,099.2

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

WISCONSIN ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CAPITALIZATION

December 31

	2007	2006
	(Millions of Dollars)	
Common Equity (see accompanying statement)	$ 3,099.2	$ 2,889.0
Preferred Stock		
Wisconsin Energy		
$.01 par value; authorized 15,000,000 shares; none outstanding	-	-
Wisconsin Electric		
Six Per Cent. Preferred Stock - $100 par value;		
authorized 45,000 shares; outstanding - 44,498 shares	4.4	4.4
Serial preferred stock -		
$100 par value; authorized 2,286,500 shares; 3.60% Series		
redeemable at $101 per share; outstanding - 260,000 shares	26.0	26.0
$25 par value; authorized 5,000,000 shares; none	-	-

outstanding			
Total Preferred Stock		30.4	30.4
Long-Term Debt			
Debentures (unsecured)	3.50% due 2007	-	250.0
	4.50% due 2013	300.0	300.0
	6.60% due 2013	45.0	45.0
	5.20% due 2015	125.0	125.0
	6-1/2% due 2028	150.0	150.0
	5.625% due 2033	335.0	335.0
	5.90% due 2035	90.0	90.0
	5.70% due 2036	300.0	300.0
	6-7/8% due 2095	100.0	100.0
Notes (secured, nonrecourse)	2% stated rate due 2011	0.2	0.2
	5.55% variable rate due 2028 (a)	-	14.6
	4.81% effective rate due 2030	2.0	2.0
	4.91% due 2008-2030	146.9	150.4
Notes (unsecured)	7.75% due 2008	0.3	0.6
	5.50% due 2008	300.0	300.0
	6.21% due 2008	20.0	20.0
	6.48% due 2008	25.4	25.4
	5-1/2% due 2009	50.0	50.0
	6.25% due 2010	10.0	10.0
	6.50% due 2011	450.0	450.0
	6.51% due 2013	30.0	30.0
	3.50% variable rate due 2015 (b)	17.4	17.4
	4.50% variable rate due 2016 (b)	67.0	67.0
	6.94% due 2028	50.0	50.0
	4.50% variable rate due 2030 (b)	80.0	80.0
	6.20% due 2033	200.0	200.0
Junior Notes (unsecured)	6.25% due 2067	500.0	-
Obligations under capital leases		157.5	231.4
Unamortized discount, net and other		(26.4)	(23.9)
Long-term debt due currently		(352.8)	(296.7)

Total Long-Term Debt	3,172.5	3,073.4
Total Capitalization	$ 6,302.1	$ 5,992.8

(a) Variable interest rate as of December 31, 2006.

(b) Variable interest rate as of December 31, 2007.

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

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WISCONSIN ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

A -- SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General:

Our consolidated financial statements include the accounts of Wisconsin Energy Corporation (Wisconsin Energy, the Company, our, we or us), a diversified holding company, as well as our subsidiaries in the following operating segments:

- ***Utility Energy Segment***

-- Consisting of Wisconsin Electric, Wisconsin Gas and Edison Sault; engaged primarily in the generation of electricity and the distribution of electricity and natural gas; and

- ***Non-Utility Energy Segment***

-- Consisting primarily of We Power; engaged principally in the design, development, construction and ownership of electric power generating facilities for long-term lease to Wisconsin Electric.

Our Corporate and Other segment primarily includes Wispark, which develops and invests in real estate. We have eliminated all significant intercompany transactions and balances from the consolidated financial statements.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of certain assets and liabilities and disclosure of contingent assets and liabilities at the date of financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Reclassifications:

We have reclassified certain prior year financial statement amounts to conform to their current year presentation. These reclassifications had no effect on total assets, net income or earnings per share.

Revenues:

We recognize energy revenues on the accrual basis and include estimated amounts for services rendered but not billed.

Our retail electric rates in Wisconsin are established by the PSCW and include base amounts for fuel and purchased power costs. The electric fuel rules in Wisconsin allow us to request rate increases if fuel and purchased power costs exceed bands established by the PSCW.

Our retail gas rates include monthly adjustments which permit the recovery or refund of actual purchased gas costs. We defer any difference between actual gas costs incurred (adjusted for a sharing mechanism) and costs recovered through rates as a current asset or liability. The deferred balance is returned to or recovered from customers at intervals throughout the year.

For information regarding revenue recognition for PTF, see Note E.

Accounting for MISO Energy Transactions:

MISO implemented the MISO Energy Markets on April 1, 2005. The MISO Energy Markets operate under both day-ahead and real-time markets. We record energy transactions in the MISO Energy Markets on a net basis for each hour.

Other Income and Deductions, Net:

We recorded the following items in Other Income and Deductions, net for the years ended December 31:

Other Income and Deductions, Net	2007	2006	2005
		(Millions of Dollars)	
Carrying Costs	$28.8	$25.0	$20.4
Gain (Loss) on Sale of Property	13.1	3.2	(3.0)
Gain on Sale of Guardian Investment	-	2.8	-
AFUDC - Equity	5.2	14.6	9.2
Other, Net	1.8	7.5	2.1
Total Other Income and Deductions, Net	$48.9	$53.1	$28.7

Property and Depreciation:

We record property, plant and equipment at cost. Cost includes material, labor, overheads and capitalized interest. Utility property also includes AFUDC - Equity. Additions to and significant replacements of property are charged to property, plant and equipment at cost; minor items are charged to maintenance expense. The cost of depreciable utility property less salvage value is charged to accumulated depreciation when property is retired.

We had the following property in service by segment at December 31:

Property In Service	2007	2006
	(Millions of Dollars)	
Utility Energy	$8,309.2	$8,781.5
Non-Utility Energy	568.2	389.5
Other	81.7	94.4
Total	$8,959.1	$9,265.4

We include capitalized software costs associated with our utility energy segment under the caption "Property, Plant and Equipment" on the Consolidated Balance Sheets. As of December 31, 2007 and 2006, the net book value of regulated capitalized software totaled $14.9 million and $17.8 million, respectively. The net book value of other capitalized software was approximately $3.6 million and $1.7 million as of December 31, 2007 and 2006, respectively. The estimated useful life of our capitalized software is 5 years.

Our utility depreciation rates are certified by the state regulatory commissions and include estimates for salvage value and removal costs. Depreciation as a percent of average depreciable utility plant was 3.7% in 2007 and 2006, and 3.9% in 2005. The decline in depreciation as a percent of average depreciable utility plant was due to new depreciation rates approved by the PSCW, which became effective January 1, 2006.

For assets other than our regulated assets, we accrue depreciation expense at straight-line rates over the estimated useful lives of the assets. Estimated useful lives for non-regulated assets are 3 to 40 years for furniture and equipment, 2 to 5 years for software and 30 to 40 years for buildings.

Our regulated utilities collect in their rates amounts representing future removal costs for many assets that do not have an associated ARO. W

e record a regulatory liability on our balance sheet for the estimated amounts we have collected in rates for future removal costs less amounts we have spent in removal activities. This regulatory liability was $664.5 million as of December 31, 2007 and $630.6 million as of December 31, 2006.

We recorded the following CWIP by segment at December 31:

	2007	2006
	(Millions of Dollars)	
Utility Energy	$309.7	$103.5

Non-Utility Energy	1,389.9	865.9
Other	64.5	23.0
Total	$1,764.1	$992.4

Allowance For Funds Used During Construction - Regulated:

AFUDC is included in utility plant accounts and represents the cost of borrowed funds (AFUDC - Debt) used during plant construction and a return on stockholders' capital (AFUDC - Equity) used for construction purposes. AFUDC - Debt is recorded as a reduction of interest expense and AFUDC - Equity is recorded in Other Income and Deductions, net.

During 2007 and 2006, Wisconsin Electric accrued AFUDC at a rate of 8.94%, as authorized by the PSCW. During 2005, the authorized rate was 10.18%. Wisconsin Electric accrues AFUDC on all electric utility NO_x, SO_2 and particulates remediation projects. Wisconsin Electric's rates were set to provide a full return on electric safety and reliability projects so AFUDC is not accrued on these projects. Wisconsin Electric accrued AFUDC on 50% of the remaining electric, gas and steam projects in CWIP and rates were set assuming that 50% of the CWIP balances were included in rate base.

During 2007 and 2006, Wisconsin Gas accrued AFUDC at a rate of 11.31%, as authorized by the PSCW. During 2005, the authorized rate was 10.32%. Wisconsin Gas accrued AFUDC on specific large construction projects during 2005. During 2007 and 2006, Wisconsin Gas accrued AFUDC on 50% of CWIP balances.

Our regulated segment recorded the following AFUDC for the years ended December 31:

	2007	2006	2005
		(Millions of Dollars)	
AFUDC - Debt	$1.8	$5.2	$4.6
AFUDC - Equity	$5.2	$14.6	$9.2

Capitalized Interest and Carrying Costs - Non-Regulated Energy:

As part of the construction of the power plants under our PTF program, we capitalize interest during construction in accordance with SFAS 34. Under the lease agreements associated with our PTF power plants, we are able to collect from utility customers the carrying costs associated with the construction of these power plants. We defer these carrying costs collected on our balance sheet and they will be amortized to revenue over the individual lease term. For further information on the accounting for capitalized interest and deferred carrying costs associated with the construction of our PTF power plants, see Note E.

Earnings Per Common Share:

We compute basic earnings per common share by dividing our net income by the weighted average number of common shares outstanding. Diluted earnings per common share reflect the potential reduction in earnings per common share that could occur when potentially dilutive common shares are added to common shares outstanding.

We derive our potentially dilutive common shares by calculating the number of shares issuable relating to stock options utilizing the treasury stock method. The future issuance of shares underlying the outstanding stock options depends on whether the exercise prices of the stock options are less than the average market price of the common shares for the respective periods. Shares that are anti-dilutive are not included in the calculation.

Materials, Supplies and Inventories:

Our inventory at December 31 consists of:

Materials, Supplies and Inventories	2007	2006
	(Millions of Dollars)	
Fossil Fuel	$125.1	$121.0
Natural Gas in Storage	140.6	188.6
Materials and Supplies	95.6	107.6
Total	$361.3	$417.2

Substantially all fossil fuel, materials and supplies and natural gas in storage inventories are recorded using the weighted-average method of accounting.

Regulatory Accounting:

Our utility energy segment accounts for its regulated operations in accordance with SFAS 71. This statement sets forth the application of GAAP to those companies whose rates are determined by an independent third-party regulator. The economic effects of regulation can result in regulated companies recording costs that have been or are expected to be allowed in the rate making process in a period different from the period in which the costs would be charged to expense by an unregulated enterprise. When this occurs, costs are deferred as assets on the balance sheet (regulatory assets) and recorded as expenses in the periods when those same amounts are reflected in rates. We defer all of our regulatory assets pursuant to specific orders or by a generic order issued by our primary regulator. Additionally, regulators can impose liabilities upon a regulated company for amounts previously collected from customers and for amounts that are expected to be refunded to customers (regulatory liabilities). We expect to recover our outstanding regulatory assets in rates over a period of no longer than 20 years. Regulatory assets and liabilities that are expected to be amortized within one year are recorded as current on the balance sheet. For further information, see Note C.

Derivative Financial Instruments:

We have derivative physical and financial instruments as defined by SFAS 133 which we report at fair value. However, our use of financial instruments is limited. For further information, see Note M.

Cash and Cash Equivalents:

Cash and cash equivalents include marketable debt securities acquired three months or less from maturity.

Restricted Cash:

Cash proceeds that we received from the sale of Point Beach that are to be used for the benefit of our customers are recorded as restricted cash.

Margin Accounts:

Cash deposited in brokerage accounts for margin requirements is recorded in Other Current Assets on our Consolidated Balance Sheets.

Asset Retirement Obligations:

We adopted SFAS 143 effective January 1, 2003. We adopted FIN 47 effective December 31, 2005. FIN 47 defines the term conditional ARO as used in SFAS 143. As defined in FIN 47, a conditional ARO refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Consistent with SFAS 143, we record a liability at fair value for a legal ARO in the period in which it is incurred. When a new legal obligation is recorded, we capitalize the costs of the liability by increasing the carrying amount of the related long-lived asset. We accrete the liability to its present value each period and depreciate the capitalized cost over the useful life of the related asset. At the end of the asset's useful life, we settle the obligation for its recorded amount or incur a gain or loss. As it relates to our regulated operations, we apply SFAS 71 and recognize regulatory assets or liabilities for the timing differences between when we recover legal AROs in rates and when we would recognize these costs under SFAS 143. For further information, see Note F.

Goodwill and Intangible Assets:

We account for goodwill and other intangible assets following SFAS 142. As of December 31, 2007 and 2006, we had $441.9 million of goodwill recorded at the utility energy segment, which related to our acquisition of Wisconsin Gas in 2000.

Under SFAS 142, goodwill and other intangibles with indefinite lives are not subject to amortization. However, goodwill and other intangibles are subject to fair value-based rules for measuring impairment, and resulting write-downs, if any, are to be reflected in operating expense. We assess the fair value of our SFAS 142 reporting unit by considering future discounted cash flows, a comparison of fair value based on public company trading multiples, and merger and acquisition transaction multiples for similar companies. This evaluation utilizes the information available under the circumstances, including reasonable and supportable assumptions and projections. We perform our annual impairment test for the reporting unit as of August 31. There was no impairment to the recorded goodwill balance as of our annual 2007 impairment test date for our reporting unit.

Impairment or Disposal of Long Lived Assets:

We carry property, equipment and goodwill related to businesses held for sale at the lower of cost or estimated fair value less costs to sell. As of December 31, 2007, we had no assets classified as Held for Sale. Consistent with SFAS 144, long-lived assets are tested for recoverability whenever events or changes in circumstances indicate that their carrying value may not be recoverable from the use and eventual disposition of the asset based on the remaining useful life. An impairment loss is recognized when the carrying amount of an asset is not recoverable and exceeds the fair value of the asset. The carrying amount of an 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. An impairment loss is measured as the excess of the carrying amount of the asset in comparison to the fair value of the asset. For further information, see Note D.

Investments:

We account for investments in other affiliated companies in which we do not maintain control using the equity method. As of December 31, 2007 and 2006, we had a total ownership interest of approximately 26.9% and 29.4% in ATC. We are represented by one out of ten ATC board members, each of whom has one vote. Due to the voting requirements, no individual member has more than 10% of the voting control. For further information regarding such investments, see Note R.

Income Taxes:

We follow the liability method in accounting for income taxes as prescribed by SFAS 109. SFAS 109 requires the recording of deferred assets and liabilities to recognize the expected future tax consequences of events that have been reflected in our financial statements or tax returns and the adjustment of deferred tax balances to reflect tax rate changes. We are required to assess the likelihood that our deferred tax assets would expire before being realized. We have established a valuation allowance against certain deferred tax assets. GAAP requires that, if we conclude in a future period that it is more likely than not that some or all of the deferred tax assets would be realized before expiration, we reverse the related valuation allowance in that period. Any change to the allowance, as a result of a change in judgment about the realization of deferred tax assets, is reported in income tax expense.

Tax credits associated with regulated operations are deferred and amortized over the life of the assets. We file a consolidated Federal income tax return. Accordingly, we allocate Federal current tax expense benefits and credits to our subsidiaries based on their separate tax computations. For further information, see Note H.

We recognize interest and penalties accrued related to unrecognized tax benefits in Income Taxes in our Consolidated Income Statements, as well as Regulatory Assets or Regulatory Liabilities in our Consolidated Balance Sheets.

We collect sales and use taxes from our customers and remit these taxes to governmental authorities. These taxes are recorded in our Consolidated Income Statements on a net basis.

Stock Options:

Effective January 1, 2006, we adopted SFAS 123R, using the modified prospective method. We use a binomial pricing model to estimate the fair value of stock options granted subsequent to December 31, 2005. Prior to January 1, 2006, we accounted for share based compensation under APB 25, Accounting for Stock Issued to Employees, and we disclosed the pro forma impact of share based compensation expense under SFAS 123. Historically, all stock options have been granted with an exercise price equal to the fair market value of the common stock on the date of grant and expire no later than ten years from the grant date. Accordingly, no compensation expense was recognized in connection with option grants. Prior to January 1, 2006, we reported benefits of tax deductions in excess of recognized compensation costs as operating cash flows. SFAS 123R requires that excess tax benefits be reported as a financing cash inflow rather than as an operating cash inflow. In addition, we previously recorded unearned stock-based compensation for non-vested restricted stock and performance share awards as

"unearned compensation" in our Consolidated Statements of Common Equity. For further discussion of this standard and the impacts to our Consolidated Financial Statements, see Note J.

The fair value of our stock options at date of grant for 2007 and 2006 was calculated using a binomial option-pricing model. For 2005, the fair value of options at the date of grant was estimated using the Black-Scholes option-pricing model with the following weighted average assumptions:

	Binomial		Black-Scholes
	2007	2006	2005
Risk free interest rate	4.7% - 5.1%	4.3% - 4.4%	4.4%
Dividend yield	2.2%	2.4%	2.5%
Expected volatility	13.0% - 20.0%	17.0% - 20.0%	19.0%
Expected life (years)	6.0	6.3	10.0

Pro forma weighted average fair value of our stock options granted	$8.72	$7.55	$8.32

B -- RECENT ACCOUNTING PRONOUNCEMENTS

Uncertainty in Income Taxes:

In July 2006, the FASB issued FIN 48, an interpretation of SFAS 109. FIN 48 clarifies the accounting for uncertainty in income taxes recognized in the enterprise's financial statements in accordance with SFAS 109. We adopted FIN 48 effective January 1, 2007. For further information, see Note H.

Fair Value Measurements:

In September 2006, the FASB issued SFAS 157. SFAS 157 provides guidance for using fair value to measure assets and liabilities, defines fair value, provides a framework for measuring fair value and expands disclosures related to fair value measurements. SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007. We partially adopted the provisions of SFAS 157 effective January 1, 2008. In accordance with FSP SFAS 157-b, we have not applied the provisions of Statement 157 to pension assets, goodwill or asset retirement obligations. The adoption of SFAS 157 did not have a significant financial impact on our consolidated financial statements.

Fair Value Option

: In February 2007, the FASB issued SFAS 159. SFAS 159 permits an entity to measure certain financial assets and financial liabilities at fair value and also establishes presentation and disclosure requirements. SFAS 159 is effective as of the beginning of an entity's first fiscal year beginning after November 15, 2007. We adopted the provisions of SFAS 159 effective January 1, 2008. The adoption of SFAS 159 did not have any financial impact on our consolidated financial statements.

C -- REGULATORY ASSETS AND LIABILITIES

Our utility energy segment accounts for its regulated operations in accordance with SFAS 71.

Our primary regulator considers our regulatory assets and liabilities in two categories, escrowed and deferred. In escrow accounting we expense amounts that are included in rates. If actual costs exceed, or are less than the amounts that are allowed in rates, the difference in cost is escrowed on the balance sheet as a regulatory asset or regulatory liability and the escrowed balance is considered in setting future rates. Under deferred cost accounting, we defer amounts to our balance sheet based upon specific orders or correspondence with our primary regulator. These deferred costs will be considered in future rate setting proceedings. As of December 31, 2007, we had approximately $58.3 million of net regulatory assets that were not earning a return.

In January 2008, the PSCW issued a rate order that, among other things, reaffirmed our accounting for the regulatory assets and liabilities identified below. In addition, the rate order provided for the immediate recovery in January 2008 of $85.0 million related to deferred fuel costs and escrowed bad debt costs. The rate order also provided for the recovery over a six year period of the balance of the deferred fuel costs, escrowed bad debt costs and escrowed transmission costs. The order also specified that the deferred Point Beach gain would be passed on to customers over a three year period. Finally, the order eliminated the use of escrow accounting for transmission costs that are incurred after December 31, 2007.

Our regulatory assets and liabilities as of December 31 consist of:

	2007	2006
	(Millions of Dollars)	
Regulatory Assets		
Deferred unrecognized pension costs	$303.8	$357.2
Escrowed electric transmission costs	240.9	192.2
Deferred income tax related	90.9	98.3
Deferred fuel related costs	86.7	79.1
Deferred plant related -- capital lease	74.7	71.8
Deferred unrecognized OPEB costs	58.9	70.4
Deferred environmental costs	63.9	68.2
Escrowed bad debt costs	61.1	57.0
Other, net	145.4	96.8
Total regulatory assets	$1,126.3	$1,091.0
Regulatory Liabilities		
Deferred Point Beach related	$906.8	$ -
Deferred cost of removal obligations	664.5	630.6
Deferred income tax related	119.4	95.4
Deferred asset retirement obligations	-	537.1
Other, net	186.7	209.0
Total regulatory liabilities	$1,877.4	$1,472.1

Under SFAS 158, which we adopted effective December 31, 2006, we have concluded that substantially all of the unrecognized costs resulting from the recognition of the funded status of our pension and OPEB plans qualify as a regulatory asset.

Our regulated subsidiaries record deferred regulatory assets and liabilities representing the future expected impact of deferred taxes on utility revenues, see Note A.

Consistent with a generic order from and past rate-making practices of the PSCW, we defer as a regulatory asset costs associated with the remediation of former manufactured gas plant sites. As of December 31, 2007, we have recorded

$63.9 million of environmental costs associated with manufactured gas plant sites as a regulatory asset, including $32.0 million of deferrals for actual remediation costs incurred and a $31.9 million accrual for estimated future site remediation, see Note S. In addition, we have deferred $6.8 million of insurance recoveries associated with the environmental costs as regulatory liabilities. We included total actual remediation costs incurred net of the related insurance recoveries in our 2006 rate case. We began amortizing these costs upon receiving PSCW approval in January 2006. The amortization period for these costs is five years.

As of December 31, 2007, we have $61.1 million of escrowed bad debt costs. In 2005 and 2004, the PSCW approved our request to account for residential bad debt costs on an escrow basis at Wisconsin Gas and Wisconsin Electric whereby they defer actual bad debt write-offs that exceed amounts allowed in rates.

D -- ASSET SALES, DIVESTITURES AND DISCONTINUED OPERATIONS

Point Beach:

Prior to September 28, 2007, Wisconsin Electric owned two 518 MW electric generating units (Unit 1 and Unit 2) at Point Beach in Two Rivers, Wisconsin. During 2007, 2006 and 2005, Point Beach provided approximately 17.3%, 25.3% and 20.0%, respectively, of Wisconsin Electric's net electric energy supply.

On September 28, 2007, Wisconsin Electric sold Point Beach to an affiliate of FPL for approximately $924 million. Pursuant to the terms of the sale agreement, the buyer purchased Point Beach, its nuclear fuel, associated inventories and assumed the obligation to decommission the plant. Wisconsin Electric retained approximately $506 million of the sales proceeds, which represents the net book value of the assets sold and certain transaction costs. In addition, Wisconsin Electric has deferred the net gain on the sale of approximately $418 million as a regulatory liability and has deposited those proceeds into a restricted cash account.

In connection with the sale, Wisconsin Electric also transferred $390 million of decommissioning funds to the buyer. Wisconsin Electric then liquidated the balance of the decommissioning trust assets and retained approximately $552 million of that cash. This cash was also placed into the restricted cash account. We are using the cash in the restricted cash account, and the interest earned on the balance, for the benefit of our customers and to pay certain taxes related to the liquidation of the qualified decommissioning trust. Our regulators are directing the manner in which these proceeds will benefit customers. As of December 31, 2007, we have recorded a regulatory liability of approximately $907 million that represents deferred gains that will be used for the benefit of our customers.

A long-term power purchase agreement with the buyer became effective upon closing of the sale. Pursuant to this agreement, Wisconsin Electric is purchasing all of the energy produced by Point Beach. The power purchase agreement extends through 2030 for Unit 1 and 2033 for Unit 2. Based on the agreement, we will be paying a predetermined price per MWh for energy delivered. Under the agreement, if our credit rating and the credit rating of Wisconsin Electric from either S&P or Moody's fall below investment grade, or if the holders of any indebtedness in excess of $100.0 million accelerate or have the right to accelerate the maturity of such indebtedness as a result of a default, we would need to provide collateral in the amount of $100.0 million (escalating at 3% per year commencing in 2024). For further information regarding our former nuclear operations, see Note I.

Minergy Neenah:

Effective September 27, 2006, we sold 100% of the membership interest in Minergy Neenah to a third party. The primary assets of Minergy Neenah were a Glass Aggregate plant and related operating contracts. The plant recycled paper sludge from area paper mills into renewable energy and glass aggregate using our patented Glass Aggregate technology. The largest source of revenue for Minergy Neenah was a long-term steam contract with an adjacent paper mill. The mill was permanently closed as of June 30, 2006. Pursuant to the steam contract, the mill owner paid Minergy Neenah a contract termination payment. In the third quarter of 2006, we received gross proceeds from the sale of the plant and the contract termination totaling $12.2 million and we recorded a net loss of $0.4 million that is included in Income from Discontinued Operations, Net of tax.

Wisvest - Calumet:

Effective May 31, 2005, we sold our Calumet facility for approximately $37.0 million in cash to Tenaska Power Fund, L.P. The primary assets of Calumet were a 308 MW natural gas-fired peaking power facility in Chicago, Illinois and related operating contracts. The transaction generated an after tax gain of approximately $4.7 million upon closing and generated approximately $32.0 million in cash tax benefits.

We have recorded the operating results of Minergy Neenah and Calumet as Income from Discontinued Operations, Net of Tax in the accompanying Consolidated Income Statements for the years ended December 31, 2006 and 2005.

The total effect on operating revenues for Calumet and Minergy Neenah were $14.3 million and $20.4 million in 2006 and 2005, respectively. The income (loss) before taxes was $2.4 million and ($6.0) million for the same years. The gain (loss) on discontinued operations for 2007, 2006 and 2005 was not material.

E -- ACCOUNTING AND REPORTING FOR POWER THE FUTURE GENERATING UNITS

Background:

As part of our PTF strategy, our non-utility subsidiary, We Power, is building four new generating units that will be leased to our utility subsidiary, Wisconsin Electric, under long-term leases that have been approved by the PSCW, our primary regulator. The leases are designed to recover the capital costs of the plant including a return. The first of the four generating units was placed in service in July 2005 and is being leased to Wisconsin Electric. Wisconsin Electric will be responsible for all of the operating costs of the PTF units once they are placed in service and we anticipate that we will recover the operating costs of these plants in rates. The accompanying consolidated financial statements eliminate all intercompany transactions between We Power and Wisconsin Electric, and reflect the cash inflows from Wisconsin Electric customers and the cash outflows to our vendors and suppliers. The PTF units include PWGS 1, PWGS 2, OC 1 and OC 2.

During Construction:

Under the terms of each lease, we collect in current rates amounts representing our pre-tax cost of capital (debt and equity) associated with capital expenditures for the PTF units. Our pre-tax cost of capital is approximately 14%. The carrying costs that we collect in rates are recorded as deferred revenue, and they will be amortized to revenue over the term of each lease, once the respective unit is placed into service. During the construction of the PTF units, we capitalize interest costs at an overall weighted-average pre-tax cost of interest of approximately 6%. Capitalized interest is included in the total cost of the PTF units.

Cash Flows:

The following table identifies key pre-tax cash outflows and inflows for the years ended December 31 related to the construction of our PTF units as compared to Wisconsin Energy overall:

	Capital Expenditures (Millions of Dollars)				Total	
	PWGS1	PWGS 2	OC 1	OC 2	PTF	WEC
2007	$ -	$94.2	$94.2	$154.9	$665.6	$1,211.5
2006	$ -	$121.3	$268.0	$76.8	$466.1	$928.7
2005	$52.6	$45.6	$141.1	$37.1	$276.4	$745.1

	Capitalized Interest (Millions of Dollars				Total	
	PWGS 1	PWGS 2	OC 1	OC 2	PTF	WEC
2007	$ -	$15.4	$41.7	$14.3	$71.4	$73.3
2006	$ -	$8.3	$19.3	$6.8	$34.4	$39.9
2005	$10.8	$2.8	$7.7	$3.0	$24.3	$28.7

	Deferred Revenue (Millions of Dollars)				Total	
	PWGS 1	PWGS 2	OC 1	OC 2	PTF	WEC
2007	$ -	$34.9	$96.4	$33.2	$164.5	$164.5
2006	$ -	$19.1	$45.3	$15.9	$80.3	$80.3
2005	$23.9	$6.3	$17.6	$6.9	$54.7	$54.7

Balance Sheet:

As noted above, we collect in current rates carrying costs that are calculated based on the cash expenditures included in CWIP multiplied by our pre-tax cost of capital. The carrying costs are recorded as deferred revenue and included in Other long-term liabilities. Our total CWIP balance includes cash expenditures, capitalized interest and accruals. The following table identifies key amounts related to our PTF units that are recorded on our balance sheet:

	CWIP - Cash Expenditures (Millions of Dollars)				Total
	PWGS 1	PWGS 2	OC 1	OC 2	PTF
December 31, 2007	$ -	$286.4	$738.6	$314.7	$1,339.7
December 31, 2006	$ -	$196.2	$487.7	$152.6	$836.5

	Total CWIP (Millions of Dollars)				Total	
	PWGS 1	PWGS 2	OC 1	OC 2	PTF	WEC
December 31, 2007	$ -	$313.3	$800.4	$339.9	$1,453.6	$1,764.1
December 31, 2006	$ -	$207.7	$517.3	$163.5	$888.5	$992.4

	Net Plant in Service (Millions of Dollars)				Total	
	PWGS 1	PWGS 2	OC 1	OC 2	PTF	WEC
December 31, 2007	$345.8	$ -	$171.2	$ -	$517.0	$5,835.2
December 31, 2006	$350.1	$ -	$ -	$ -	$350.1	$5,841.7

	Deferred Revenue (Millions of Dollars)				Total	
	PWGS 1	PWGS 2	OC 1	OC 2	PTF	WEC
December 31, 2007	$65.5	$62.2	$162.4	$57.6	$347.7	$347.7
December 31, 2006	$68.3	$27.5	$66.0	$24.4	$186.2	$186.2

Income Statement:

Once the PTF units are placed in service, we expect to recover in rates the lease costs which reflect the authorized cash construction cost of the units plus a return. The authorized cash costs are established by the PSCW. The authorized cash costs exclude capitalized interest since carrying costs are recovered during the construction of the units. The lease payments are expected to be levelized, except that OC 1 and OC 2 will be recovered on a levelized basis that has a one time 10.6% escalation after the first 5 years of the leases. The leases established a set return on equity component of 12.7% after tax. The interest component of the return is determined up to 180 days prior to the date that the units are placed in service.

We recognize revenues related to the lease payments that are included in our rates. In addition, our revenues include the amortization of the deferred revenues that reflect the carrying costs that are collected during construction. The deferred revenue is amortized on a straight line basis over the lease term. We depreciate the units on a straight-line basis over their expected service life.

In July 2005, PWGS 1 was placed in service. This asset had a cost of approximately $364.3 million which included approximately $31.1 million of capitalized interest. The asset is being depreciated over its estimated useful life of approximately 37 years. The cost of the plant, plus a return, is expected to be recovered through Wisconsin Electric's rates over a 25 year period at an annual amount of approximately $48 million.

In November 2007, the coal handling system for Oak Creek was placed into service. This asset had a cost of approximately $171.2 million. This asset is being depreciated over its estimated useful life of approximately 40 years. The cost of the system, plus a return, is expected to be recovered through Wisconsin Electric's rates over a 32 year period at an annual amount of approximately $24 million.

F -- ASSET RETIREMENT OBLIGATIONS

The following table presents the change in our AROs during 2007:

	Balance at 12/31/06	Liabilities Incurred	Liabilities Settled	Accretion	Cash Flow Revisions	Balance at 12/31/07
	(Millions of Dollars)					
AROs	$371.7	$3.9	($338.4)	$14.9	$2.4	$54.5

Our AROs were significantly reduced due to the sale of Point Beach. Upon closing of the sale, the buyer assumed the liability to decommission the plant, including the ARO spent fuel and the obligation to return the site to greenfield status.

In March 2005, the FASB issued FIN 47. FIN 47 defines a conditional ARO as a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. We adopted FIN 47 effective December 31, 2005. At adoption, we recorded additional AROs related to asbestos removal costs.

The adoption of FIN 47 had no impact on our net income in 2007, 2006 or 2005. As it relates to our regulated operations, we apply SFAS 71 and recognize regulatory assets or liabilities for the timing differences between when we recover legal AROs in rates and when we would recognize these costs under FIN 47. This treatment is consistent with the adoption of SFAS 143 for our regulated operations.

G -- VARIABLE INTEREST ENTITIES

Under FIN 46 and FIN 46R, the primary beneficiary of a variable interest entity must consolidate the related assets and liabilities.

We continue to evaluate our tolling and purchased power agreements with third parties on a quarterly basis. After making an exhaustive effort, we concluded that for three of these agreements, we are unable to obtain the information necessary to determine whether these entities are variable interest entities. Pursuant to the terms of two of the three agreements, we deliver fuel to the entity's facilities and receive electric power. We pay the entity a "toll" to convert our fuel into the electric energy. The output of the facility is available for us to dispatch during the term of the respective agreement. In the other agreement, we have rights to the firm capacity of the entity's facility. We have approximately $530.9 million of required payments over the remaining terms of these three agreements, which expire over the next 15 years. We believe the required payments will continue to be recoverable in rates. We account for one of these agreements as a capital lease.

In April 2006, the FASB issued FSP FIN 46R-6. As required, we adopted FSP FIN 46R-6 effective July 1, 2006 for any new arrangements entered into after the effective date. Although the adoption of FSP FIN 46R-6 did not have a material financial impact in the current period, we currently are unable to determine the potential impact in future periods.

H -- INCOME TAXES

The following table is a summary of income tax expense for each of the years ended December 31:

Income Taxes	2007	2006	2005
	(Millions of Dollars)		
Current tax expense	$300.6	$229.0	$63.7
Deferred income taxes, net	(80.0)	(49.7)	90.2
Investment tax credit, net	(4.2)	(4.3)	(4.7)

Total Income Tax Expense	$216.4	$175.0	$149.2

The provision for income taxes for each of the years ended December 31 differs from the amount of income tax determined by applying the applicable U.S. statutory federal income tax rate to income before income taxes as a result of the following:

	2007		2006		2005	
Income Tax Expense	Amount	Effective Tax Rate	Amount	Effective Tax Rate	Amount	Effective Tax Rate
			(Millions of Dollars)			
Expected tax at statutory federal tax rates	$193.5	35.0%	$170.6	35.0%	$158.5	35.0%
State income taxes net of federal tax benefit	26.9	4.9%	24.1	4.9%	21.2	4.7%
Reversal of valuation allowances	-	- %	(5.8)	(1.1%)	(16.3)	(3.6%)
Investment tax credit restored	(4.2)	(0.8%)	(4.3)	(0.9%)	(4.7)	(1.0%)
Other, net	0.2	0.1%	(9.6)	(2.0%)	(9.5)	(2.1%)
Total Income Tax Expense	$216.4	39.2%	$175.0	35.9%	$149.2	33.0%

The components of SFAS 109 deferred income taxes classified as net current liabilities and net long-term liabilities at December 31 are as follows:

	2007	2006
	(Millions of Dollars)	
Deferred Tax Assets		
Current		
Employee benefits and compensation	$13.6	$13.9

Recoverable gas costs	1.3	9.0
Deferred gain	98.0	-
Other	3.9	3.8
Total Current Deferred Tax Assets	$116.8	$26.7
Non-current		
Employee benefits and compensation	134.4	110.4
Deferred revenues	122.1	84.4
Construction advances	97.3	84.8
Deferred gain	77.5	-
Property-related	59.6	73.2
Emission allowances	20.3	19.0
State NOL's	14.6	25.8
Decommissioning trust	-	98.1
Other	40.6	38.3
Total Non-current Deferred Tax Assets	$566.4	$534.0
Total Deferred Tax Assets	$683.2	$560.7
Deferred Tax Liabilities		
Current		
Prepaid items	$40.4	$39.1
Uncollectible account expense	11.7	9.1
Total Current Deferred Tax Liabilities	$52.1	$48.2
Non-current		
Property-related	$820.7	$848.5
Deferred transmission costs	95.9	76.5
Employee benefits and compensation	79.3	71.8
Investment in transmission affiliate	50.8	44.3
Other	71.4	65.8
Total Non-current Deferred Tax Liabilities	$1,118.1	$1,106.9
Total Deferred Tax Liabilities	$1,170.2	$1,155.1

Consolidated Balance Sheet Presentation	2007	2006
Current Deferred Tax Asset (Liability)	$64.6	($21.5)
Non-current Deferred Tax Liability	($551.7)	($572.9)

Consistent with ratemaking treatment, deferred taxes are offset in the above table for temporary differences which have related regulatory assets or liabilities.

As of December 31, 2007 and 2006, we had recorded $3.3 million and $3.4 million, respectively, of valuation allowances primarily related to the uncertainty of our ability to benefit from state loss carryforwards in the future. In June 2005, we re-evaluated our state loss carryforwards in conjunction with our new PTF plants and concluded that it was more likely than not that we will be able to utilize certain tax benefits associated with state net operating

losses of the Parent that have been carried forward from prior years. As such, in 2006 and 2005 we reversed $5.8 million and $16.3 million of valuation allowances associated with the state tax net operating losses that have been carried forward to future years. The remaining state loss carryforwards begin to expire in 2008 and have been reduced by a valuation allowance.

We adopted the provisions of FIN 48 on January 1, 2007. As of the date of adoption, the amount of unrecognized tax benefits, accrued interest, and penalties were approximately $36.3 million, $4.2 million and $1.2 million, respectively. The impact of adopting FIN 48 was not material. A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

	(Millions of Dollars)
Balance, January 1, 2007	$36.3
Additions based on tax positions related to the current year	-
Additions for tax positions of prior years	0.4
Reductions for tax positions of prior years	(2.7)
Settlements during the period	(0.8)
Balance, December 31, 2007	$33.2

The amount of unrecognized tax benefits as of December 31, 2007 excludes FIN 48 related deferred tax assets of $8.5 million. As of December 31, 2007, the net amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate for continuing operations was approximately $9.2 million.

We recognize interest and penalties accrued related to unrecognized tax benefits as a component of income tax expense. For the year ended December 31, 2007, we recognized approximately $3.0 million of accrued interest and no penalties in the Consolidated Income Statement. We had approximately $6.2 million of interest and $1.0 million of penalties accrued on the Consolidated Balance Sheet as of December 31, 2007.

Within the next 12 months, we anticipate the resolution of approximately $1.2 million of unrecognized tax benefits due to the expiration of statute of limitations in jurisdictions other than our primary tax jurisdictions related to prior year transactions.

Our primary tax jurisdictions include Federal and the State of Wisconsin. Currently, the tax years of 2004 through 2007 are subject to Federal examination and the tax years of 2003 through 2007 are subject to examination by the

State of Wisconsin.

I -- NUCLEAR OPERATIONS

The sale of Point Beach was completed on September 28, 2007. The discussion below reflects decommissioning and nuclear operations through September 28, 2007.

Nuclear Decommissioning:

We recorded decommissioning expense in amounts equal to the amounts collected in rates and funded to the external trusts. Nuclear decommissioning costs were accrued over the expected service lives of the nuclear generating units and were included in electric rates. The decommissioning funding was $11.2 million through September 2007 and $17.6 million for each of the years ended 2006 and 2005. We liquidated our decommissioning trust assets as part of the sale of Point Beach. We had the following investments in Nuclear Decommissioning Trusts, stated at fair value, as of December 31, 2007 and 2006:

	2007	2006
	(Millions of Dollars)	
Funding and Realized Earnings	$ -	$607.2
Unrealized Gains	-	274.4
Total Investments	$ -	$881.6

As of December 31, 2006, approximately 66.5% of the trust funds were invested in equity securities and 33.5% were invested in debt securities. In accordance with SFAS 115, Wisconsin Electric's debt and equity security investments in the trusts were classified as available for sale. Gains and losses on the fund were determined on the basis of specific identification; net unrealized gains on the fund were recorded as part of the fund. Our investments in the trusts were recorded at fair value and we were allowed regulatory treatment for the fair value adjustment. Realized gains and losses for the years ended December 31, 2007 and 2006 were as follows:

	2007	2006
	(Millions of Dollars)	
Realized Gains	$320.6	$21.2
Realized (Losses)	(8.3)	(10.6)

Net Realized Gain	$312.3	$10.6

Total gains and total losses by security type for the years ended December 31, 2007 and 2006 were as follows:

2007	Total Gains	Total (Losses)	Net Gain (Loss)
Debt	$2.2	($3.0)	($0.8)
Equity	318.4	(5.3)	313.1
Total	$320.6	($8.3)	$312.3

2006	Total Gains	Total (Losses)	Net Gain (Loss)
Debt	$1.4	($5.2)	($3.8)
Equity	296.5	(7.7)	288.8
Total	$297.9	($12.9)	$285.0

Decontamination and Decommissioning Fund:

The Energy Policy Act of 1992 established a D&D Fund for the DOE's nuclear fuel enrichment facilities. Deposits to the D&D Fund are derived in part from special assessments on utilities using enrichment services. In October 2006, a final payment was made to the DOE. As a result, a liability no longer exists for this fund. The deferred regulatory asset was amortized to nuclear fuel expense and included in utility rates through September 2007.

J -- COMMON EQUITY

As of December 31, 2007 and 2006, we had 325,000,000 shares of common stock authorized under our charter, of which 116,943,072 and 116,969,063 common shares, respectively, were outstanding. All share-based compensation is fulfilled by purchases on the open market by our independent agents and do not dilute shareholders' ownership.

Share-Based Compensation Plans:

We have a plan that was approved by stockholders that enables us to provide a long-term incentive through equity interests in Wisconsin Energy, to outside directors, selected officers and key employees of the Company. The plan provides for the granting of stock options, stock appreciation rights, restricted stock awards and performance shares. Awards may be paid in common stock, cash or a combination thereof. Effective January 1, 2006, we adopted SFAS 123R using the modified prospective method. We utilize the straight-line attribution method for recognizing share-based compensation expense under SFAS 123R. Accordingly, for employee awards, equity classified share-based compensation cost is measured at the grant date based on the fair value of the award, and is recognized as expense over the requisite service period. There were no modifications to the terms of outstanding stock options during the period.

The following table summarizes recorded pre-tax share-based compensation expense and the related tax benefit for share-based awards made to our employees and directors as of December 31:

	2007	2006
	(Millions of Dollars)	
Stock options	$ 12.2	$ 7.6
Performance units	5.4	7.0
Restricted stock	1.2	1.2
Share-based compensation expense	$ 18.8	$ 15.8
Related Tax Benefit	$ 7.6	$ 6.3

Prior to January 1, 2006, we accounted for share based compensation under APB 25 and, in accordance with SFAS 123R, we would have reported 2005 compensation expense relating to stock options, performance awards and restricted stock of $3.7 million, $3.9 million and $1.2 million, respectively. The related tax benefit for these items was $3.5 million.

Stock Options:

The exercise price of a stock option under the plan is to be no less than 100% of the common stock's fair market value on the grant date and options may not be exercised within six months of the grant date except in the event of a change in control. Option grants consist of non-qualified stock options and vest on a cliff-basis after a three year period. Generally, options expire no later than ten years from the date of grant. For further information regarding stock-based compensation and the valuation of our stock options, see Note A.

The following is a summary of our stock options issued through December 31, 2007:

Stock Options	Number of Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (Millions)
Outstanding as of January 1, 2007	7,721,826	$30.52		
Granted	1,371,590	$47.76		
Exercised	(1,388,213)	$26.59		
Forfeited	(10,964)	$35.66		
	7,694,239	$34.30	6.5	$110.9

Outstanding as of December 31, 2007				
Exercisable as of December 31, 2007	4,227,996	$29.12	5.2	$82.8

We expect that substantially all of the outstanding options as of December 31, 2007 will be exercised.

In January 2008, the Compensation Committee awarded 1,362,160 non-qualified stock options at an average market price of $48.04 to our officers and key executives under its normal schedule of awarding long-term incentive compensation.

The intrinsic value of options exercised during the years ended December 31, 2007, 2006 and 2005 was $30.0 million, $21.1 million and $27.7 million, respectively. Cash received from options exercised during the years ended December 31, 2007, 2006 and 2005 was $36.1 million, $26.8 million and $47.0 million, respectively. The related tax benefit for the same periods was approximately $11.2 million, $8.4 million and $11.1 million, respectively.

The following table summarizes information about stock options outstanding as of December 31, 2007:

	Options Outstanding			Options Exercisable		
		Weighted-Average			Weighted-Average	
Range of Exercise Prices	Number of Options	Exercise Price	Remaining Contractual Life (Years)	Number of Options	Exercise Price	Remaining Contractual Life (Years)
$12.79 to $23.05	999,498	$21.54	3.4	999,498	$21.54	3.4
$25.31 to $31.07	1,480,122	$26.99	4.8	1,480,122	$26.99	4.8
$33.44 to $47.76	5,214,619	$38.81	7.5	1,748,376	$35.24	6.4
	7,694,239	$34.30	6.5	4,227,996	$29.12	5.2

The following table summarizes information about our non-vested options through December 31, 2007:

Non-Vested Stock Options	Number of Options	Weighted-Average Fair Value
Non-vested as of January 1, 2007	2,587,849	$7.94
Granted	1,371,590	$8.72
Vested	(486,032)	$8.22
Forfeited	(7,164)	$8.18
Non-Vested as of December 31, 2007	3,466,243	$8.21

As of December 31, 2007, total compensation costs related to non-vested stock options not yet recognized was approximately $8.2 million, which is expected to be recognized over the next 20 months on a weighted-average basis.

Restricted Shares:

The Compensation Committee has also approved restricted stock grants to certain key employees and directors. The following restricted stock activity occurred during 2007:

Restricted Shares	Number of Shares	Weighted-Average Market Price
Outstanding as of January 1, 2007	184,665	
Granted	14,139	$47.19
Released / Forfeited	(52,498)	$27.25
Outstanding as of December 31, 2007	146,306	

Recipients of the restricted shares, who have the right to vote the shares and to receive dividends, are not required to provide consideration to us other than rendering service. Forfeiture provisions on the restricted stock generally expire 10 years after award grant subject to an accelerated expiration schedule for some of the shares based on the achievement of certain financial performance goals.

We record the market value of the restricted stock awards on the date of grant and then we charge their value to expense over the vesting period of the awards. We also adjust expense for acceleration of vesting due to achievement of performance goals. The intrinsic value of restricted stock vesting was $2.9 million, $0.9 million and $1.2 million for the years ended December 31, 2007, 2006, and 2005, respectively. The related tax benefit was $1.1 million, $0.5 million, and $0.5 million, respectively.

As of December 31, 2007, total compensation cost related to restricted stock not yet recognized was approximately $2.1 million, which is expected to be recognized over the next 44 months on a weighted-average basis.

Performance Units:

In January 2008, 2007 and 2006 the Compensation Committee granted 133,855, 136,905 and 150,281 performance units, respectively, to officers and other key employees under the Wisconsin Energy Performance Unit Plan. Under the grants, the ultimate number of units which will be awarded is dependent upon the achievement of certain financial performance of our stock over a three year period. Under the terms of the award, participants may earn between 0% and 175% of the base performance award. We are accruing compensation costs over the three year period based on our estimate of the final expected value of the award. In July 2006, the Compensation Committee amended the terms of performance shares granted in 2004 to allow the recipients to receive cash or common stock upon settlement. During the third quarter of 2006, we transferred $6.3 million from Common Equity to Other Liabilities to reflect participant elections to take cash under this amendment. All grants after 2004 will be settled in cash. Performance units/shares earned as of December 31, 2007 and 2006 vested and had a total intrinsic value of $5.2 million and $7.2 million, respectively. They were subsequently distributed to our officers and key employees in January 2008 and 2007. The related tax benefit realized due to the distribution of performance units/shares was approximately $1.8 million and $2.1 million, respectively. As of December 31, 2007, total compensation cost related to performance units not yet recognized was approximately $6.0 million, which is expected to be recognized over the next 20 months on a weighted-average basis.

Common Stock Activity:

In 2004, we announced that we did not expect to issue new shares under our various employee benefit plans and our dividend reinvestment and share purchase plan; rather, we instructed the independent plan agents to begin purchasing the shares in the open market. In that regard, no new shares of common stock were issued in 2007, 2006 or 2005.

During 2007 and 2006, our plan agents purchased 1.4 million shares at a cost of $67.8 million and 1.1 million shares at a cost of $48.0 million, respectively, to fulfill exercised stock options and restricted stock awards. In 2007 and 2006, we received proceeds of $36.1 million and $26.8 million, respectively, related to the exercise of stock options.

Restrictions:

Wisconsin Energy's ability to pay common dividends primarily depends on the availability of funds received from our principal utility subsidiaries, Wisconsin Electric and Wisconsin Gas. During 2007, Wisconsin Electric and Wisconsin Gas collectively provided Wisconsin Energy with $259.6 million of dividends. In the future, as the new PTF plants are placed in service, we expect that We Power will also be a source of distributions for Wisconsin Energy.

Various financing arrangements and regulatory requirements impose certain restrictions on the ability of our principal utility subsidiaries to transfer funds to Wisconsin Energy in the form of cash dividends, loans or advances. In addition, under Wisconsin law, Wisconsin Electric and Wisconsin Gas are prohibited from loaning funds, either directly or indirectly, to Wisconsin Energy.

The January 2008 rate order requires Wisconsin Electric and Wisconsin Gas to maintain capital structures as set forth by the PSCW. These capital structures differ from GAAP as they reflect regulatory adjustments. Wisconsin Electric is required to maintain a common equity ratio range of between 48.5% and 53.5% and Wisconsin Gas is to maintain a capital structure which has a common equity range of between 45.0% and 50.0%. Wisconsin Electric and Wisconsin Gas must obtain PSCW approval if they pay dividends above the test year levels that would cause either company to fall below authorized levels of common equity.

Wisconsin Electric may not pay common dividends to Wisconsin Energy under Wisconsin Electric's Restated Articles of Incorporation if any dividends on Wisconsin Electric's outstanding preferred stock have not been paid. In addition, pursuant to the terms of Wisconsin Electric's 3.60% Serial Preferred Stock, Wisconsin Electric's ability to declare common dividends would be limited to 75% or 50% of net income during a twelve month period if Wisconsin Electric's common stock equity to total capitalization, as defined in the preferred stock designation, is less than 25% and 20%, respectively.

We have the option to defer interest payments on the Junior Notes, from time to time, for one or more periods of up to 10 consecutive years per period. During any period in which we defer interest payments, we may not declare or pay any dividends or distributions on, or redeem, repurchase or acquire, our common stock.

As of December 31, 2007, the restricted net assets of consolidated and unconsolidated subsidiaries and our equity in undistributed earnings of 50% or less owned investees accounted for by the equity method total approximately $2.7 billion. This amount exceeds 25% of our consolidated net assets as of December 31, 2007.

See Note L for discussion of certain financial covenants related to the bank back-up credit agreements of Wisconsin Energy, Wisconsin Electric and Wisconsin Gas.

We do not believe that these restrictions will materially affect our operations or limit any dividend payments in the foreseeable future.

K -- LONG-TERM DEBT

Debentures and Notes:

As of December 31, 2007, the maturities and sinking fund requirements of our long-term debt outstanding (excluding obligations under capital leases) were as follows:

	(Millions of Dollars)
2008	$349.4
2009	53.9
2010	14.1
2011	454.3
2012	4.4
Thereafter	2,518.1
Total	$3,394.2

We amortize debt premiums, discounts and debt issuance costs over the lives of the debt and we include the costs in interest expense.

In May 2007, we issued $500 million of Junior Notes. Due to certain features of the Junior Notes, rating agencies consider them to be hybrid instruments with a combination of debt and equity characteristics. These securities were issued under a shelf registration statement filed with the SEC in May 2007 for an unlimited number of debt securities, which became effective upon filing. The Junior Notes bear interest at 6.25% per year until May 15, 2017. Beginning May 15, 2017, the Junior Notes bear interest at the three-month London Interbank Offered Rate (LIBOR) plus 2.1125%, reset quarterly. The proceeds from this issuance were used to repay short-term debt incurred to both fund PTF and for other working capital purposes.

In connection with the issuance of the Junior Notes, we executed the RCC for the benefit of persons that buy, hold or sell a specified series of long-term indebtedness (covered debt). Our 6.20% Senior Notes due April 1, 2033 have been initially designated as the covered debt under the RCC. The RCC provides that we may not redeem, defease or purchase and our subsidiaries may not purchase any Junior Notes on or before May 15, 2037, unless, subject to certain limitations described in the RCC, during the 180 days prior to the date of redemption, defeasance or purchase, we have received a specified amount of proceeds from the sale of qualifying securities.

During December 2007, Wisconsin Electric retired $250 million of 3.50% Notes due December 1, 2007. Short-term debt was issued to retire those notes.

In November 2006, Wisconsin Electric issued $300 million of 5.70% Debentures due December 1, 2036. The securities were issued under an existing $665 million shelf registration statement filed with the SEC. The net proceeds from the sale were used to retire Wisconsin Electric's $200 million of 6-5/8% Debentures due November 15, 2006 at their scheduled maturity and to repay outstanding commercial paper incurred for working capital requirements.

In July 2005, PWGS issued $155 million of 4.91% senior notes in a private placement. The senior notes have a mortgage style repayment feature with monthly payments of approximately $0.9 million, including principal and interest. The final payment is due July 15, 2030. The senior notes are secured by a collateral assignment of the leases between PWGS and Wisconsin Electric relating to the first PWGS gas unit that went into service in July 2005.

Obligations Under Capital Leases:

In 1997, Wisconsin Electric entered into a 25-year power purchase contract with an unaffiliated independent power producer. The contract, for 236 MW of firm capacity from a gas-fired cogeneration facility, includes no minimum energy requirements. When the contract expires in 2022, Wisconsin Electric may, at its option and with proper notice, renew for another ten years or purchase the generating facility at fair value or allow the contract to expire. We account for this contract as a capital lease and recorded the leased facility and corresponding obligation under the capital lease at the estimated fair value of the plant's electric generating facilities. We are amortizing the leased facility on a straight-line basis over the original 25-year term of the contract.

We treat the long-term power purchase contract as an operating lease for rate-making purposes and we record our minimum lease payments as purchased power expense on the Consolidated Income Statements. We paid a total of $27.1 million, $26.1 million and $25.2 million in minimum lease payments during 2007, 2006 and 2005, respectively. We record the difference between the minimum lease payments and the sum of imputed interest and amortization costs calculated under capital lease accounting as a deferred regulatory asset on our Consolidated Balance Sheets (see Regulatory Assets - Deferred plant related -- capital lease in Note C). Due to the timing and the amounts of the minimum lease payments, we expect the regulatory asset to increase to approximately $78.5 million by the year 2009, at which time the regulatory asset will be reduced to zero over the remaining life of the contract. The total obligation under the capital lease was $157.5 million at December 31, 2007 and will decrease to zero over the remaining life of the contract.

Wisconsin Electric had a nuclear fuel leasing arrangement with Wisconsin Electric Fuel Trust, which was treated as a capital lease. Under this arrangement, Wisconsin Electric leased and amortized nuclear fuel to fuel expense as power was generated. In connection with the sale of Point Beach, the nuclear fuel leasing arrangement with Wisconsin Electric Fuel Trust was dissolved in September 2007. Wisconsin Electric terminated the lease and paid off all of Wisconsin Electric Fuel Trust's outstanding commercial paper, aggregating $76.2 million.

Following is a summary of our capitalized leased facilities and nuclear fuel as of December 31:

Capital Lease Assets	2007	2006
	(Millions of Dollars)	
Leased Facilities		
	$140.3	$140.3

Long-term power purchase commitment		
Accumulated amortization	(58.4)	(52.8)
Total Leased Facilities	$81.9	$87.5
Nuclear Fuel		
Under capital lease	$ -	$136.0
Accumulated amortization	-	(70.4)
In process/stock	-	65.3
Total Nuclear Fuel	$ -	$130.9

Future minimum lease payments under our capital lease and the present value of our net minimum lease payments as of December 31, 2007 are as follows:

Capital Lease Obligations	Power Commitment
	(Millions of Dollars)
2008	$33.6
2009	34.9
2010	36.2
2011	37.5
2012	38.9
Thereafter	256.3
Total Minimum Lease Payments	437.4
Less: Estimated Executory Costs	(98.5)
Net Minimum Lease Payments	338.9
Less: Interest	(181.4)
Present Value of Net Minimum Lease Payments	157.5
Less: Due Currently	(3.4)
	$154.1

L -- SHORT-TERM DEBT

Short-term notes payable balances and their corresponding weighted-average interest rates as of December 31 consist of:

	2007		2006	
Short-Term Debt	Balance	Interest Rate	Balance	Interest Rate
	(Millions of Dollars, except for percentages)			
Commercial paper	$900.7	5.18%	$911.9	5.37%

As of December 31, 2007, we had approximately $1.7 billion of available unused lines under our bank back-up credit facilities on a consolidated basis. Our bank back-up credit facilities expire in March 2011 and April 2011.

The following information relates to Short-Term Debt for the years ending December 31:

	2007	2006
	(Millions of Dollars, except for percentages)	
Maximum Short-Term Debt Outstanding	$974.5	$943.7
Average Short-Term Debt Outstanding	$721.8	$549.8
Weighted-Average Interest Rate	5.40%	5.13%

Wisconsin Energy, Wisconsin Electric and Wisconsin Gas have entered into various bank back-up credit agreements to maintain short-term credit liquidity which, among other terms, require the companies to maintain, subject to certain exclusions, a minimum total funded debt to capitalization ratio of less than 70%, 65% and 65%, respectively.

The Wisconsin Energy, Wisconsin Electric and Wisconsin Gas bank back-up credit agreements contain customary covenants, including certain limitations on the respective companies' ability to sell assets. The credit agreements also contain customary events of default, including payment defaults, material inaccuracy of representations and

warranties, covenant defaults, bankruptcy proceedings, certain judgments, ERISA defaults and change of control. In addition, pursuant to the terms of Wisconsin Energy's credit agreement, Wisconsin Energy must ensure that certain of its subsidiaries comply with many of the covenants contained therein.

As of December 31, 2007, we were in compliance with all covenants.

M -- DERIVATIVE INSTRUMENTS

We follow SFAS 133, as amended by SFAS 149, which requires that every derivative instrument be recorded on the balance sheet as an asset or liability measured at its fair value and that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. For most energy related physical and financial contracts in our regulated operations that qualify as derivatives under SFAS 133, the PSCW allows the effects of the fair market value accounting to be offset to regulatory assets and liabilities. As of December 31, 2007, we recognized $24.3 million in regulatory assets and $14.5 million in regulatory liabilities related to derivatives in comparison to $36.6 million in regulatory assets at December 31, 2006.

For the years ended December 31, 2007, 2006 and 2005, we reclassified $0.3 million, $0.4 million and $0.6 million, respectively, in treasury lock agreement settlement payments deferred in Accumulated Other Comprehensive Income, as an increase to Interest Expense. We estimate that during the next twelve months, $0.4 million will be reclassified from Accumulated Other Comprehensive Income as a reduction in earnings.

N -- FAIR VALUE OF FINANCIAL INSTRUMENTS

The carrying amount and estimated fair value of certain of our recorded financial instruments as of December 31 are as follows:

	2007		2006	
Financial Instruments	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(Millions of Dollars)			
Nuclear decommissioning assets	$ -	$ -	$881.6	$881.6
Preferred stock, no redemption required	$30.4	$22.3	$30.4	$22.6
Long-term debt including current portion	$3,394.2	$3,313.2	$3,162.6	$3,172.1

The carrying value of cash and cash equivalents, net accounts receivable, accounts payable and short-term borrowings approximates fair value due to the short term nature of these instruments. Prior to the September 2007 sale of Point Beach, the nuclear decommissioning assets were carried at fair value as reported by the trustee, see Note I. The fair value of our preferred stock is estimated based upon the quoted market value for the same or similar issues. The fair value of our long-term debt, including the current portion of long-term debt, but excluding capitalized leases, is estimated based upon quoted market value for the same or similar issues or upon the quoted market prices of U.S. Treasury issues having a similar term to maturity, adjusted for the issuing company's bond rating and the present value of future cash flows. The fair values of derivative financial instruments and associated margin accounts are equal to their carrying values as of December 31, 2007.

O -- BENEFITS

Pensions and Other Post-retirement Benefits:

We have noncontributory defined benefit pension plans that cover substantially all of our employees. The plans provide defined benefits based upon years of service and final average salary.

We also have OPEB plans covering substantially all of our employees. The health care plans are contributory with participants' contributions adjusted annually; the life insurance plans are noncontributory. The accounting for the health care plans anticipates future cost-sharing changes to the written plans that are consistent with our expressed intent to maintain the current cost sharing levels. The post-retirement health care plans include a limit on our share of costs for recent and future retirees. We use a year-end measurement date for all of our pension and OPEB plans.

In September 2006, the FASB issued SFAS 158, which requires employers to recognize all obligations related to their pension and OPEB plans and to quantify the funded status of the pension and OPEB plans as an asset or liability on their statement of financial position. In addition, SFAS 158 requires employers to measure the funded status of their plans as of the date of their year-end statement of financial position.

We adopted SFAS 158 prospectively on December 31, 2006, and will continue to use a year-end measurement date for all of our pension and OPEB plans. Due to the regulated nature of our business, we have concluded that substantially all of the unrecognized costs resulting from the recognition of the funded status of our pension and OPEB plans qualify as a regulatory asset.

The following table presents details about our pension and OPEB plans:

	Pension		OPEB	
	2007	2006	2007	2006
	(Millions of Dollars)			
Change in Benefit Obligation				
Benefit Obligation at January 1	$1,253.6	$1,299.7	$332.9	$331.9
Service cost	29.5	33.8	11.2	12.3
Interest cost	71.2	69.6	19.2	17.9
Plan amendments	(4.4)	3.6	1.0	-
Actuarial (gain)	(41.6)	(51.5)	(15.7)	(18.0)
Divestitures	(38.9)	-	(7.9)	-
Benefits paid	(108.4)	(101.6)	(11.4)	(12.1)
Federal subsidy on benefits paid	N/A	N/A	1.7	0.9

Benefit Obligation at December 31	$1,161.0	$1,253.6	$331.0	$332.9
Change in Plan Assets				
Fair Value at January 1	$1,057.7	$976.9	$203.7	$186.0
Actual earnings on plan assets	64.0	121.5	6.7	14.7
Employer contributions	26.7	60.9	2.5	15.1
Divestitures	(32.8)	-	-	-
Benefits paid	(108.4)	(101.6)	(11.4)	(12.1)
Fair Value at December 31	$1,007.2	$1,057.7	$201.5	$203.7
Net Liability	($153.8)	($195.9)	($129.5)	($129.2)

The accumulated benefit obligation for all defined benefit plans was $1,147.8 million and $1,218.7 million as of December 31, 2007 and 2006, respectively.

The following table shows the amounts that have not yet been recognized in our net periodic benefit cost as of December 31:

	Pension		OPEB	
	2007	2006	2007	2006
	(Millions of Dollars)			
Net Regulatory Assets				
Net actuarial loss	$ 281.0	$ 326.9	$ 91.3	$ 107.4
Prior service costs (credits)	17.9	30.3	(37.1)	(53.6)
Transition obligation	-	-	1.6	2.1
Total	$ 298.9	$ 357.2	$ 55.8	$ 55.9

The estimated net actuarial loss and prior service cost for our pension plans that will be amortized as a component of net periodic benefit costs during 2008 are $14.9 million and $3.7 million, respectively. The estimated net actuarial loss, prior service credit and transition obligation for our OPEB plans that will be amortized as a component of net periodic benefit cost during 2008 are $6.1 million, ($12.5) million and $0.3 million, respectively.

Information for pension plans with an accumulated benefit obligation in excess of the fair value of assets as of December 31 is as follows:

	2007	2006
	(Millions of Dollars)	
Projected benefit obligation	$1,161.0	$1,253.6
Accumulated benefit obligation	$1,147.8	$1,218.7
Fair value of plan assets	$1,007.2	$1,057.7

The components of net periodic pension and OPEB costs for the years ended December 31 are as follows:

	Pension			OPEB		
	2007	2006	2005	2007	2006	2005
	(Millions of Dollars)					
Net Periodic Benefit Cost						
Service cost	$29.5	$33.8	$33.3	$11.2	$12.3	$13.6
Interest cost	71.2	69.6	69.7	19.2	17.9	21.0
Expected return on plan assets	(83.9)	(81.6)	(87.6)	(15.5)	(14.9)	(15.4)
Amortization of:						
Transition obligation	-	-	-	0.3	0.3	1.3
Prior service cost (credit)	5.5	5.4	5.2	(12.5)	(13.4)	(2.8)
Actuarial loss	15.8	23.4	20.6	7.1	8.8	7.7
Net Periodic Benefit Cost	$38.1	$50.6	$41.2	$9.8	$11.0	$25.4

In connection with the sale of Point Beach in September 2007, we incurred a $3.7 million net settlement/curtailment credit related to our benefit plans. We have deferred this net gain as a regulatory liability.

Weighted-Average assumptions used to determine benefit obligations at Dec. 31						
Discount rate	6.05%	5.75%	5.50%	6.10%	5.75%	5.50%

Rate of compensation increase	4.5 to 5.0	4.5 to 5.0	4.5 to 5.0	N/A	N/A	N/A
Weighted-Average assumptions used to determine net cost for year ended Dec. 31						
Discount rate	5.75%	5.50%	5.75%	5.75%	5.50%	5.75%
Expected return on plan assets	8.5	8.5	9.0	8.5	8.5	9.0
Rate of compensation increase	4.5 to 5.0	4.5 to 5.0	4.5 to 5.0	N/A	N/A	N/A
Assumed health care cost trend rates at Dec. 31						
Health care cost trend rate assumed for next year (Pre 65 / Post 65)				8/11	9/11	10/10
Rate that the cost trend rate gradually adjusts to				5	5	5
Year that the rate reaches the rate it is assumed to remain at				2014	2011	2011

The expected long-term rate of return on plan assets was 8.5% in 2007 and 2006 and 9.0% in 2005. This return expectation on plan assets was determined by reviewing actual pension historical returns as well as calculating expected total trust returns using the weighted average of long-term market returns for each of the asset categories utilized in the pension fund.

Other Post-retirement Benefits Plans:

We use various Employees' Benefit Trusts to fund a major portion of OPEB. The majority of the trusts' assets are mutual funds or commingled indexed funds.

A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	1% Increase	1% Decrease
	(Millions of Dollars)	
Effect on		
Post-retirement benefit obligation	$25.0	($21.2)
Total of service and interest cost components	$3.7	($3.0)

In October 2005, we announced that we were offering to our retirees a Medicare Advantage program as an option within our existing post-retirement medical and drug plans. The Medicare Advantage program is part of the Medicare Prescription Drug, Improvement and Modernization Act of 2003, and offers post-65 medical and drug benefits through private insurance carriers. The Medicare Advantage program is expected to reduce the cost of post-65 medical and drug costs for our retirees and the Company. Due to this change, we remeasured the fair value of our OPEB plans in the fourth quarter of 2005 in accordance with SFAS 106. In 2005, the impact of this remeasurement and the FSP SFAS 106-2 benefit was approximately a $4.4 million reduction to SFAS 106 expense.

Plan Assets:

In our opinion, current pension trust assets and amounts which are expected to be contributed to the trusts in the future will be adequate to meet pension payment obligations to current and future retirees. Our pension plans asset allocation at December 31, 2007 and 2006, and our target allocation for 2008, by asset category, are as follows:

Asset Category	Target Allocation	Actual Allocation	
	2008	2007	2006
Equity Securities	65%	63%	61%
Debt Securities	35%	37%	39%
Total	100%	100%	100%

Our OPEB plans asset allocation at December 31, 2007 and 2006, and our target allocation for 2008, by asset category, are as follows:

Asset Category	Target Allocation	Actual Allocation	
	2008	2007	2006
Equity Securities	61%	61%	45%
Debt Securities	39%	38%	54%
Other	-	1%	1%
Total	100%	100%	100%

Our common stock is not included in equity securities. Investment managers are specifically prohibited from investing in our securities or any affiliate of ours except if part of a commingled fund or index fund.

The target asset allocations were established by our Investment Trust Policy Committee, which oversees investment matters related to all of our funded benefit plans. The asset allocations are monitored by the Investment Trust Policy Committee.

Cash Flows:

Employer Contributions	Pension	OPEB
	(Millions of Dollars)	
2005	$4.2	$12.3
2006	$60.9	$15.1
2007	$26.7	$2.5

We expect to contribute $45.4 million to fund pension benefits and $18.1 million to fund OPEB plans in 2008. Of the $45.4 million expected to be contributed to fund pension benefits in 2008, we estimate $38.6 million will be for our qualified pension plans. We contributed $20 million to our qualified pension plans during 2007. In 2006, we contributed $55.4 million to our qualified pension plans, and we did not make a contribution to our qualified pension plan during 2005.

The entire contribution to the OPEB plans during 2007 was discretionary as the plans are not subject to any minimum regulatory funding requirements.

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The following table identifies our expected benefit payments over the next 10 years.

Year	Pension	Gross OPEB	Expected Medicare Part D Subsidy
		(Millions of Dollars)	
2008	$82.6	$19.4	($0.5)
2009	$88.8	$21.4	($0.5)
2010	$93.6	$22.9	($0.4)
2011	$103.3	$23.8	($0.3)
2012	$110.6	$21.9	$ -
2013-2017	$549.2	$121.8	$ -

Savings Plans:

We sponsor savings plans which allow employees to contribute a portion of their pre-tax and or after-tax income in accordance with plan-specified guidelines. Under these plans we expensed matching contributions of $12.1 million, $10.4 million and $10.7 million during 2007, 2006 and 2005, respectively.

P -- GUARANTEES

We enter into various guarantees to provide financial and performance assurance to third parties on behalf of our affiliates. As of December 31, 2007, we had the following guarantees:

	Maximum Potential Future Payments	Outstanding as of December 31, 2007	Liability Recorded as of December 31, 2007
		(Millions of Dollars)	
Wisconsin Energy			
Non-Utility Energy	$ -	$ -	$ -
Other	2.5	2.5	-
Wisconsin Electric	2.8	0.1	-
Subsidiary	6.1	6.1	0.9
Total	$11.4	$8.7	$0.9

A non-utility energy segment guarantee in support of Wisvest-Connecticut, which we sold in December 2002 to PSEG, provides financial assurance for potential obligations relating to environmental remediation under the original purchase agreement for Wisvest-Connecticut with the United Illuminating Company. The potential obligations for environmental remediation, which are unlimited, are reimbursable by PSEG under the terms of the sale agreement in the event that we are required to perform under the guarantee.

Other guarantees support obligations of our affiliates to third parties under loan agreements and surety bonds. In the event our affiliates fail to perform, we would be responsible for the obligations.

Wisconsin Electric is subject to the potential retrospective premiums that could be assessed under its insurance program.

Subsidiary guarantees support loan obligations and surety bonds between our affiliates and third parties. In the event our affiliates fail to perform, our subsidiary would be responsible for the obligations.

Postemployment benefits:

Postemployment benefits provided to former or inactive employees are recognized when an event occurs. The estimated liability, excluding severance benefits, for such benefits was $13.9 million as of December 31, 2007.

Q -- SEGMENT REPORTING

Our reportable operating segments at December 31, 2007 include a utility energy segment and a non-utility energy segment. We have organized our reportable operating segments based in part upon the regulatory environment in which our utility subsidiaries operate. In addition, the segments are managed separately because each business requires different technology and marketing strategies. The accounting policies of the reportable operating segments are the same as those described in Note A.

Our utility energy segment primarily includes our electric and natural gas utility operations. Our electric utility operation engages in the generation, distribution and sale of electric energy in southeastern (including metropolitan Milwaukee), east central and northern Wisconsin and in the Upper Peninsula of Michigan. Our natural gas utility operation is engaged in the purchase, distribution and sale of natural gas to retail customers and the transportation of customer-owned natural gas throughout Wisconsin. Our non-utility energy segment derives its revenues primarily from the ownership of electric power generating facilities for long-term lease to Wisconsin Electric and economic interests in other energy-related entities.

Summarized financial information concerning our reportable operating segments for each of the years ended December 31, 2007, 2006 and 2005, is shown in the following table. The segment information below includes income from discontinued operations as a result of sales of non-utility businesses announced or completed in 2006 and 2005:

	Reportable Operating Segments		Corporate & Other (b) &	
	Energy		Reconciling	Total
Year Ended	Utility	Non-Utility (a)	Eliminations (c)	Consolidated
	(Millions of Dollars)			
December 31, 2007				
Operating Revenues	$4,224.8	$75.7	($62.7)	$4,237.8
Depreciation, Decommissioning and Amortization	$315.2	$12.1	$0.9	$328.2
Operating Income (Loss)	$586.0	$47.4	($4.9)	$628.5
Equity in Earnings of Unconsolidated Affiliates	$43.1	$ -	$0.9	$44.0
Interest Expense, Net	$113.8	$7.4	$46.4	$167.6
Income Tax Expense (Benefit)	$221.2	$14.3	($19.1)	$216.4
Income from Discontinued Operations, Net of Tax	$ -	$ -	($0.9)	($0.9)
Net Income (Loss)	$338.0	$23.7	($26.1)	$335.6
Capital Expenditures	$540.3	$669.3	$1.9	$1,211.5
Total Assets	$10,243.7	$1,974.5	($497.9)	$11,720.3

	Reportable Operating Segments		Corporate & Other (b) &	
	Energy		Reconciling	Total
Year Ended	Utility	Non-Utility (a)	Eliminations (c)	Consolidated

	(Millions of Dollars)			
December 31, 2006				
Operating Revenues	$3,979.0	$69.1	($51.7)	$3,996.4
Depreciation, Decommissioning and Amortization	$314.0	$11.2	$1.2	$326.4
Operating Income (Loss)	$532.8	$43.1	($7.4)	$568.5
Equity in Earnings of Unconsolidated Affiliates	$38.6	$ -	$4.5	$43.1
Interest Expense, net	$108.0	$14.8	$49.9	$172.7
Income Tax Expense (Benefit)	$192.3	$11.7	($29.0)	$175.0
Income from Discontinued Operations, Net of Tax (b)	$ -	$ -	$3.9	$3.9
Net Income (Loss)	$315.2	$18.3	($17.1)	$316.4
Capital Expenditures	$459.9	$468.6	$0.2	$928.7
Total Assets	$10,133.9	$1,265.2	($268.9)	$11,130.2
December 31, 2005				
Operating Revenues	$3,793.0	$40.0	($17.5)	$3,815.5
Depreciation, Decommissioning and Amortization	$324.1	$5.9	$2.0	$332.0
Operating Income	$542.4	$19.5	$1.0	$562.9
Equity in Earnings (Losses) of Unconsolidated Affiliates	$34.6	$ -	($0.6)	$34.0
Interest Expense, net	$106.1	$14.4	$52.9	$173.4
Income Tax Expense (Benefit)	$184.9	$4.5	($40.2)	$149.2
Income from Discontinued Operations, Net of Tax	$ -	$5.0	$0.1	$5.1
Net Income (Loss)	$314.2	$6.7	($12.2)	$308.7
Capital Expenditures	$458.6	$276.6	$9.9	$745.1
Total Assets	$9,601.6	$749.5	$110.9	$10,462.0

(a) The non-utility energy segment includes discontinued operations for the Calumet operations. The sale of Calumet was completed effective May 31, 2005. In 2005, Calumet is reported as discontinued operations for the five months ended May 31, 2005. The after tax gain of $4.7 million recorded for the sale is included in Income from Discontinued Operations, Net of Tax. Certain overheads reported for Calumet continued to exist following the sale and are reported in continuing operations. Certain other costs are directly attributable to the discontinued operations.

(b) Other includes all other non-utility activities, primarily non-utility real estate investment and development by Wispark, non-utility investment in renewable energy and recycling technologies by Minergy as well as interest on corporate debt. A gain on the sale of the manufacturing segment in 2004 resulted in a 2006 tax adjustment and is reflected in Corporate and Other. In 2006, we sold Minergy Neenah and the gain from the sale is included in Income from Discontinued Operations, Net. Certain overheads reported for

Minergy Neenah continue to exist following the sale and are reported in continuing operations, while certain other costs are directly attributable to the discontinued operations. Total assets in other includes Minergy Neenah assets held for sale of $17.4 million at December 31, 2005.

(c) An elimination for intersegment revenues of $70.3 million, $64.1 million and $36.3 million is included in Operating Revenues for 2007, 2006 and 2005, respectively. This elimination is primarily between We Power and Wisconsin Electric.

R -- RELATED PARTIES

We receive and/or provide certain services to other associated companies in which we have an equity investment.

American Transmission Company LLC:

As of December 31, 2007, we have a 26.9% interest in ATC. We pay ATC for transmission and other related services it provides. In addition, we provide a variety of operational, maintenance and project management work for ATC, which are reimbursed to us by ATC. Under our PTF plan, we are required to pay the cost of needed transmission infrastructure upgrades. ATC will reimburse us for these costs when the units are placed into service. At December 31, 2007 and 2006, we had a receivable of $35.8 million and $27.2 million, respectively, for these items.

Nuclear Management Company:

Prior to the Point Beach sale, we had a partial ownership in NMC. NMC held the operating licenses of Point Beach. Upon the sale of Point Beach, NMC transferred the operating licenses to the buyer and our relationship with NMC was terminated.

We provided and received services from the following associated companies during 2007, 2006 and 2005:

Equity Investee	2007	2006	2005
		(Millions of Dollars)	
Services Provided			
-ATC	$17.8	$16.6	$20.9
Services Received			
-ATC	$176.8	$149.4	$130.1
-NMC	$50.6	$65.2	$61.2

As of December 31, 2007 and 2006 our Consolidated Balance Sheets included receivable and payable balances with the following associated companies:

Equity Investee	2007	2006
	(Millions of Dollars)	
Services Provided		
-ATC	$1.1	$1.2
Services Received		
-ATC	$14.5	$12.5
-NMC	$ -	$ 5.7

S -- COMMITMENTS AND CONTINGENCIES

Capital Expenditures:

We have made certain commitments in connection with 2008 capital expenditures. During 2008, we estimate that total capital expenditures will be approximately $1.2 billion.

Operating Leases:

We enter into long-term purchase power contracts to meet a portion of our anticipated increase in future electric energy supply needs. These contracts expire at various times through 2013. Certain of these contracts were deemed to qualify as operating leases. In addition, we have various other operating leases including leases for vehicles and coal cars.

Future minimum payments for the next five years and thereafter for our operating lease contracts are as follows:

	(Millions of Dollars)
2008	$37.0
2009	23.6
2010	20.7
2011	20.9
2012	14.5
Thereafter	18.4
Total	$135.1

Divested Assets:

Pursuant to the sale of Point Beach, we have agreed to indemnification provisions customary to transactions involving the sale of nuclear assets.

Pursuant to the terms of the sale agreement for Minergy Neenah, we have agreed to customary indemnification provisions related to post-closing obligations and other matters. Our maximum aggregate exposure under the indemnification provisions is $0.3 million.

Pursuant to the terms of the sale agreement for Calumet, Wisvest has agreed to customary indemnification provisions related to environmental conditions and other matters. Except for retention of the full exposure to indemnify the buyer for environmental claims related to certain property no longer leased or owned by Wisvest or any of its subsidiaries, Wisvest's maximum aggregate exposure under the indemnification provisions is $35 million. Pursuant to the terms of the agreement, we have guaranteed post-closing obligations under the agreement, including indemnity obligations.

Pursuant to the terms of the sales agreement for the manufacturing business, Wisconsin Energy agreed to customary indemnification provisions related to certain environmental, asbestos, and product liability matters. In addition, the amount of cash taxes and future deferred income tax benefits are subject to a number of factors including appraisals of the fair value of Wisconsin Gas assets and applicable tax laws. Any changes in the estimates of taxes and indemnification matters will be recorded as an adjustment to the gain on sale and reported in discontinued operations in the period the adjustment is determined. We have established reserves related to these customary indemnification and tax matters.

Environmental Matters:

We periodically review our exposure for environmental remediation costs as evidence becomes available indicating that our liability has changed. Given current information, including the following, we believe that future costs in excess of the amounts accrued and/or disclosed on all presently known and quantifiable environmental contingencies will not be material to our financial position or results of operations.

We have a program of comprehensive environmental remediation planning for former manufactured gas plant sites and coal-ash disposal sites. We perform ongoing assessments of manufactured gas plant sites and related disposal sites used by Wisconsin Electric and Wisconsin Gas, and coal ash disposal/landfill sites used by Wisconsin Electric, as discussed below. We are working with the WDNR in our investigation and remediation planning. At this time, we cannot estimate future remediation costs associated with these sites beyond those described below.

Manufactured Gas Plant Sites:

We have identified several sites at which Wisconsin Electric, Wisconsin Gas, or a predecessor company historically owned or operated a manufactured gas plant. These sites have been substantially remediated or are at various stages of investigation, monitoring and remediation. We have also identified other sites that may have been impacted by historical manufactured gas plant activities. Based upon ongoing analysis, we estimate that the future costs for detailed site investigation and future remediation costs may range from $25 to $50 million over the next ten years. This estimate is dependent upon several variables including, among other things, the extent of remediation, changes in technology and changes in regulation. As of December 31, 2007, we have established reserves of $31.9 million related to future remediation costs.

The PSCW has allowed Wisconsin utilities, including Wisconsin Electric and Wisconsin Gas, to defer the costs spent on the remediation of manufactured gas plant sites, and has allowed for these costs to be recovered in rates over five years. Accordingly, we have recorded a regulatory asset for remediation costs.

Ash Landfill Sites:

Wisconsin Electric aggressively seeks environmentally acceptable, beneficial uses for its coal combustion by-products. However, these coal-ash by-products have been, and to a small degree continue to be, disposed of in company-owned, licensed landfills. Some early designed and constructed landfills may allow the release of low levels of constituents resulting in the need for various levels of monitoring or adjusting. Where Wisconsin Electric has become aware of these conditions, efforts have been expended to define the nature and extent of any release, and work has been performed to address these conditions. The costs of these efforts are recovered under the fuel clause for Wisconsin Electric and are expensed as incurred. During 2007, 2006 and 2005, Wisconsin Electric incurred $0.8 million, $0.5 million and $0.1 million, respectively, in coal-ash remediation expenses. As of December 31, 2007, we have no reserves established related to ash landfill sites.

EPA - Consent Decree:

In April 2003, Wisconsin Electric and the EPA announced that a Consent Decree had been reached that resolved all issues related to a request for information that had been issued by the EPA. In July 2003, the Consent Decree was amended to include the State of Michigan. Under the Consent Decree, Wisconsin Electric agreed to significantly reduce its air emissions from its coal-fired generating facilities. The reductions are expected to be achieved by 2013 through a combination of installing new pollution control equipment, upgrading existing equipment and retiring certain older units. Through December 31, 2007, we have spent approximately $381.0 million associated with implementing the Consent Decree. The total cost of implementing this agreement is estimated to be $1.0 billion through the year 2013. The U.S. District Court for the Eastern District of Wisconsin approved the amended Consent Decree and entered it in October 2007.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Wisconsin Energy Corporation:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Wisconsin Energy Corporation and subsidiaries (the "Company") as of December 31, 2007 and 2006, and the related consolidated statements of income, common equity, and cash flows for each of the three years in the period ended December 31, 2007. Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements and the financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedules based on our 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2007 and 2006, and the results of its operations and its 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, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2007, based on the criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2008 expressed an unqualified opinion on the Company's internal control over financial reporting.

DELOITTE & TOUCHE LLP

Milwaukee, Wisconsin

February 27, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Wisconsin Energy Corporation:

We have audited the internal control over financial reporting of Wisconsin Energy Corporation and subsidiaries (the "Company") as of December 31, 2007, based on the criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible 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 an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel 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 (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) 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 (3) 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 the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on the criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedules as of and for the year ended December 31, 2007 of the Company and our report dated February 27, 2008 expressed an unqualified opinion on those financial statements and financial statement schedules.

DELOITTE & TOUCHE LLP

Milwaukee, Wisconsin

February 27, 2008

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Our management, with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of our disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the Exchange Act)) as of the end of the period covered by this report. Based upon such evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of such period, our disclosure controls and procedures are effective (i) in recording, processing, summarizing and reporting, on a timely basis, information required to be disclosed by us in the reports that we file or submit under the Exchange Act and (ii) to ensure that information required to be disclosed in the reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosure.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of Wisconsin Energy Corporation's and subsidiaries internal control over financial reporting based on the framework in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its evaluation under the framework in Internal Control - Integrated Framework, our management concluded that Wisconsin Energy Corporation's and subsidiaries internal control over financial reporting was effective as of December 31, 2007.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of the effectiveness of internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Deloitte & Touche LLP, an independent registered public accounting firm, as auditors of our financial statements has issued an attestation report on the effectiveness of Wisconsin Energy Corporation's and subsidiaries internal control over financial reporting as of December 31, 2007. Deloitte & Touche LLP's report is included in this report.

Changes in Internal Control Over Financial Reporting

There has not been any change in our internal control over financial reporting during the fourth quarter of 2007 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE OF THE REGISTRANT

The information under "Proposal 1: Election of Directors - Terms Expiring in 2009", "Section 16(a) Beneficial Ownership Reporting Compliance", "Corporate Governance - Frequently Asked Questions: What is the process used to identify director nominees and how do I recommend a nominee to the Corporate Governance Committee?", "Corporate Governance - Frequently Asked Questions: Are the Audit and Oversight, Corporate Governance and Compensation Committees comprised solely of independent directors?", "Corporate Governance - Frequently Asked

Questions: Are all the members of the audit committee financially literate and does the committee have an audit committee financial expert?" and "Committees of the Board of Directors - Audit and Oversight" in our definitive Proxy Statement on Schedule 14A to be filed with the SEC for our Annual Meeting of Stockholders to be held May 1, 2008 (the "2008 Annual Meeting Proxy Statement") is incorporated herein by reference. Also see "Executive Officers of the Registrant" in Part I of this report.

We have adopted a written code of ethics, referred to as our Code of Business Conduct, that all of our directors, executive officers and employees, including the principal executive officer, principal financial officer and principal accounting officer, must comply with. We have posted our Code of Business Conduct on our Internet website, www.wisconsinenergy.com. We have not provided any waiver to the Code for any director, executive officer or other employee. Any amendments to, or waivers for directors and executive officers from, the Code of Business Conduct will be disclosed on our website or in a current report on Form 8-K.

Our Internet website, www.wisconsinenergy.com, also contains our Corporate Governance Guidelines and the charters of our Audit and Oversight, Corporate Governance and Compensation Committees.

Our Code of Business Conduct, Corporate Governance Guidelines and committee charters are also available without charge to any stockholder of record or beneficial owner of our common stock by writing to the corporate secretary, Susan H. Martin, at our principal business office, 231 West Michigan Street, P.O. Box 1331, Milwaukee, Wisconsin 53201.

ITEM 11. EXECUTIVE COMPENSATION

The information under "COMPENSATION, DISCUSSION AND ANALYSIS","EXECUTIVE OFFICERS' COMPENSATION","DIRECTOR COMPENSATION", "Committees of the Board of Directors - Compensation" and "COMPENSATION COMMITTEE REPORT" in the 2008 Annual Meeting Proxy Statement is incorporated herein by reference.

ITEM 12.
SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The security ownership information called for by Item 12 of Form 10-K is incorporated herein by reference to this information included under "WEC Common Stock Ownership" in the 2008 Annual Meeting Proxy Statement.

EQUITY COMPENSATION PLAN INFORMATION

The following table sets forth information about our equity compensation plans as of December 31, 2007:

	(a)	(b)	(c)

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders	7,615,077 (1)	$34.48	4,295,318
Equity compensation plans not approved by security holders	-	-	-
Total (2)	7,615,077	$34.48	4,295,318

(1) Represents options to purchase our common stock granted under our 1993 Omnibus Stock Incentive Plan, as amended.

(2) Also outstanding were options to purchase 79,162 shares of our common stock at a weighted average exercise price of $16.86 per share granted under the stock option plans of WICOR and assumed in connection with the acquisition of WICOR in April 2000. No further awards were or will be made under the WICOR stock option plans.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

The information under "Corporate Governance - Frequently Asked Questions: Who are the independent directors?", "Corporate Governance - Frequently Asked Questions: What are the Board's standards of independence" and "CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS" in the 2008 Annual Meeting Proxy Statement is incorporated herein by reference. A full description of the guidelines our Board uses to determine director independence is located in Appendix A of our Corporate Governance Guidelines, which can be found on our website, www.wisconsinenergy.com.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information regarding the fees paid to, and services performed by, our independent auditors and the pre-approval policy of our audit and oversight committee under "Independent Auditors' Fees and Services" in the 2008 Annual Meeting Proxy Statement is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) 1. FINANCIAL STATEMENTS AND REPORTS OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM INCLUDED IN PART II OF THIS REPORT

Consolidated Income Statements for the three years ended December 31, 2007.

Consolidated Balance Sheets at December 31, 2007 and 2006.

Consolidated Statements of Cash Flows for the three years ended December 31, 2007.

Consolidated Statements of Common Equity for the three years ended December 31, 2007.

Consolidated Statements of Capitalization at December 31, 2007 and 2006.

Notes to Consolidated Financial Statements.

Reports of Independent Registered Public Accounting Firm.

2. FINANCIAL STATEMENT SCHEDULES INCLUDED IN PART IV OF THIS REPORT

Schedule I Condensed Parent Company Financial Statements, including Income Statements and Cash Flows for the three years ended December 31, 2007 and Balance Sheets at December 31, 2007 and 2006.

Schedule II, Valuation and Qualifying Accounts, for the three years ended December 31, 2007.

Other schedules are omitted because of the absence of conditions under which they are required or because the required information is given in the financial statements or notes thereto.

3. EXHIBITS AND EXHIBIT INDEX

See the Exhibit Index included as the last part of this report, which is incorporated herein by reference. Each management contract and compensatory plan or arrangement required to be filed as an exhibit to this report is identified in the Exhibit Index by two asterisks (**) following the description of the exhibit.

WISCONSIN ENERGY CORPORATION

INCOME STATEMENTS

(Parent Company Only)

SCHEDULE I -- CONDENSED PARENT COMPANY
FINANCIAL STATEMENTS

	Year Ended December 31		
	2007	2006	2005
	(Millions of Dollars)		
Other Income, Net	$23.4	$25.5	$20.6
Corporate Expense	3.3	7.5	6.1
Financing Costs	70.3	65.5	65.4
Loss before Taxes	(50.2)	(47.5)	(50.9)
Income Tax Benefit	20.9	21.5	36.9
Loss after Taxes	(29.3)	(26.0)	(14.0)
Equity in Subsidiaries' Continuing Operations	365.8	338.5	317.6
Income from Continuing Operations	336.5	312.5	303.6
Income from Discontinued Operations including Equity in Subsidiaries' Discontinued Operations	(0.9)	3.9	5.1
Net Income	$335.6	$316.4	$308.7

See accompanying notes to condensed parent company financial statements.

WISCONSIN ENERGY CORPORATION

STATEMENTS OF CASH FLOWS

(Parent Company Only)

SCHEDULE I - CONDENSED PARENT COMPANY
FINANCIAL STATEMENTS - (Cont'd)

	Year Ended December 31		
	2007	2006	2005
	(Millions of Dollars)		
Operating Activities			
Net income	$335.6	$316.4	$308.7
Reconciliation to cash			
Equity in subsidiaries' earnings	(365.8)	(340.0)	(318.2)
Dividends from subsidiaries	268.7	276.6	187.6
Deferred income taxes, net	13.1	4.8	(26.4)
Accrued income taxes, net	35.6	(68.8)	34.0
Change in - Other current assets	0.1	-	-
Change in - Other current liabilities	5.5	(3.6)	(0.8)
Change in - Accounts receivable	(245.9)	(26.7)	109.8
Other	(9.4)	8.0	16.1
Cash Provided by Operating Activities	37.5	166.7	310.8
Investing Activities			
Proceeds from asset sales, net	-	38.5	-
Change in notes receivable from associated companies	1.0	1.0	1.0
Capital contributions to associated companies	(273.7)	(447.6)	(84.0)
Other	(40.9)	(18.7)	(10.9)
Cash Used In Investing Activities	(313.6)	(426.8)	(93.9)
Financing Activities			
	36.1	26.8	47.0

Issuance of common stock and exercise of stock options			
Purchase of common stock	(67.8)	(48.0)	(75.1)
Dividends paid on common stock	(116.9)	(107.6)	(102.9)
Issuance of long-term debt	493.0	10.0	-
Retirement of long-term debt	-	(250.0)	-
Change in short-term debt	(86.3)	573.9	(44.5)
Other	20.0	13.2	0.4
Cash Provided by (Used In) Financing Activities	278.1	218.3	(175.1)
Change in Cash and Cash Equivalents	2.0	(41.8)	41.8
Cash and Cash Equivalents at Beginning of Year	1.0	42.8	1.0
Cash and Cash Equivalents at End of Year	$3.0	$1.0	$42.8
Cash Paid (Received) For			
Interest (net of amount capitalized)	$63.5	$62.4	$60.9
Income taxes (net of refunds)	($70.5)	$32.0	($57.0)

See accompanying notes to condensed parent company financial statements.

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WISCONSIN ENERGY CORPORATION

BALANCE SHEETS

(Parent Company Only)

SCHEDULE I - CONDENSED PARENT COMPANY FINANCIAL STATEMENTS - (Cont'd)

	December 31	
	2007	2006
	(Millions of Dollars)	
Assets		
Current Assets		

Cash and cash equivalents	$ 3.0	$ 1.0
Accounts and notes receivable		
from associated companies	471.4	224.0
Prepaid taxes	69.0	85.1
Other	0.3	0.4
Total Current Assets	543.7	310.5
Property and Investments		
Investment in subsidiary companies	4,517.6	4,127.5
Other	67.6	26.8
Total Property and Investments	4,585.2	4,154.3
Deferred Charges and Other Assets	99.1	116.8
Total Assets	$ 5,228.0	$ 4,581.6

Liabilities and Equity

Current Liabilities		
Long-term debt due currently	$ 300.0	$ -
Short-term debt	487.7	573.9
Other	67.3	48.9
Total Current Liabilities	855.0	622.8
Long-Term Debt	1,149.3	954.4
Other Long-Term Liabilities	124.5	115.4
Total Long-Term Liabilities	124.5	115.4
Total Stockholder's Equity	3,099.2	2,889.0
Total Liabilities and Equity	$ 5,228.0	$ 4,581.6

See accompanying notes to condensed parent company financial statements.

WISCONSIN ENERGY CORPORATION

NOTES TO FINANCIAL STATEMENTS

(Parent Company Only)

SCHEDULE I - CONDENSED PARENT COMPANY
FINANCIAL STATEMENTS - (Cont'd)

1. For Parent Company only presentation, investment in subsidiaries are accounted for using the equity method. The condensed Parent Company financial statements and notes should be read in conjunction with the consolidated financial statements and notes of Wisconsin Energy Corporation appearing in this Annual Report on Form 10-K.

2. Wisconsin Energy's ability as a holding company to pay common dividends primarily depends on the availability of funds received from the Parent Company's principal utility subsidiaries, Wisconsin Electric and Wisconsin Gas. During 2007, Wisconsin Electric and Wisconsin Gas collectively provided Wisconsin Energy with $259.6 million of dividends. In the future, as the new PTF plants are placed in service, it is expected that We Power will also be a source for dividends to Wisconsin Energy.

Various financing arrangements and regulatory requirements impose certain restrictions on the ability of the Parent Company's principal utility subsidiaries to transfer funds to the Parent Company in the form of cash dividends or advances. In addition, under Wisconsin law, Wisconsin Electric and Wisconsin Gas are prohibited from loaning funds, either directly or indirectly, to the Parent Company.

Wisconsin Energy does not believe that these restrictions will materially affect the Parent Company's operations or limit any dividend payments in the foreseeable future.

3. As of December 31, 2007, the maturities of the Parent Company long-term debt outstanding were as follows:

	(Millions of Dollars)
2008	$300.0
2009	-
2010	10.0
2011	450.0
2012	-
Thereafter	700.0
Total	$ 1,460.0

Wisconsin Energy amortizes debt premiums, discounts and debt issuance costs over the lives of the debt and includes the costs in interest expense.

In May 2007, Wisconsin Energy issued $500 million of Junior Notes. Due to certain features of the Junior Notes, rating agencies consider them to be hybrid instruments with a combination of debt and equity characteristics. These securities were issued under a shelf registration statement filed with the SEC in May 2007 for an unlimited number of debt securities, which became effective upon filing. The Junior Notes bear interest at 6.25% per year until May 15, 2017. Beginning May 15, 2017, the Junior Notes bear interest at the three-month London Interbank Offered Rate (LIBOR) plus 2.1125%, reset quarterly. The proceeds from this issuance were used to repay short-term debt incurred to both fund PTF and for other working capital purposes.

In connection with the issuance of the Junior Notes, Wisconsin Energy executed the RCC for the benefit of persons that buy, hold or sell a specified series of long-term indebtedness (covered debt). Wisconsin Energy's 6.20% Senior Notes due April 1, 2033 have been initially designated as the covered debt under the RCC. The RCC provides that Wisconsin Energy may not redeem, defease or purchase and our subsidiaries may not purchase any Junior Notes on or before May 15, 2037, unless, subject to certain limitations described in the RCC, during the 180 days prior to the

date of redemption, defeasance or purchase, we have received a specified amount of proceeds from the sale of qualifying securities.

Wisconsin Energy has entered into a bank back-up credit agreement to maintain short-term liquidity which, among other terms, requires Wisconsin Energy to maintain, subject to certain exclusions, a minimum total funded debt to capitalization ratio of less than 70%.

Wisconsin Energy's bank back-up credit agreement contains customary covenants, including certain limitations on its ability to sell assets. The credit agreement also contains customary events of default, including payment defaults, material inaccuracy of representations and warranties, covenant defaults, bankruptcy proceedings, certain judgments, ERISA defaults and change of control. In addition, pursuant to the terms of its credit agreement, Wisconsin Energy must ensure that certain of its subsidiaries comply with many of the covenants contained therein.

As of December 31, 2007, Wisconsin Energy was in compliance with all covenants.

4. Wisconsin Energy and certain of its subsidiaries enter into various guarantees to provide financial and performance assurance to third parties on behalf of affiliates. As of December 31, 2007, Wisconsin Energy had the following guarantees:

	Maximum Potential Future Payments	Outstanding at Dec 31, 2007	Liability Recorded at Dec 31, 2007
		(Millions of Dollars)	
Wisconsin Energy Guarantees			
Utility	$14.8	$14.8	$ -
Non-Utility Energy	406.0	290.8	-
Other	4.5	4.3	-
Total	$425.3	$309.9	$ -
Letters of Credit	$1.5	$0.2	$ -

Utility guarantees support obligations of the utility segment under surety bonds, worker's compensation and interconnection agreements.

Wisconsin Energy's guarantees in support of our non-utility Energy segment guaranty performance and payment obligations of We Power and Wisvest. A guarantee in support of Wisvest-Connecticut which we sold in December 2002 to PSEG provides financial assurance for potential obligations relating to environmental remediation under the original purchase agreement with the United Illuminating Company. The potential obligations for environmental remediation, which are unlimited, are reimbursable by PSEG under the terms of the sale agreement in the event that Wisconsin Energy is required to perform under the guarantee. Guarantees also support obligations to third parties under the agreement with PSEG for the sale of Wisvest - Connecticut and post-closing obligations including indemnity obligations related to environmental condition and other matters under the Calumet facility sale agreement which was effective May 31, 2005. Wisconsin Energy's maximum aggregate exposure under the indemnification provisions of the Calumet facility sale agreement, except for retention of the full exposure to indemnify for environmental claims related to certain property no longer leased or owned by Wisconsin Energy or its subsidiaries, is $35 million.

The guarantees which support We Power are for obligations under purchase, construction and lease agreements with the utility segment and third parties.

Wisconsin Energy's other guarantees support an environmental indemnification, which is unlimited, associated with the Minergy Neenah plant and indemnifications related to the post-closing obligations under the Minergy Neenah sale agreement which was effective September 7, 2006.

Wisconsin Energy's other guarantees also support obligations to third parties under purchase and loan agreements and surety bonds. In the event the guarantee fails to perform, Wisconsin Energy would be responsible for the obligations.

SCHEDULE II
VALUATION AND QUALIFYING ACCOUNTS

Allowance for Doubtful Accounts	Balance at Beginning of the Period	Expense	Deferral	Net Write-offs	Balance at End of the Period
			(Millions of Dollars)		
December 31, 2007	$35.1	$38.2	$8.9	($44.2)	$38.0
December 31, 2006	$36.6	$36.5	$3.7	($41.7)	$35.1
December 31, 2005	$40.1	$26.8	$17.2	($47.5)	$36.6

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

WISCONSIN ENERGY CORPORATION

By /s/GALE E. KLAPPA

Date: February 28, 2008

Gale E. Klappa, Chairman of the Board, President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

/s/GALE E. KLAPPA Gale E. Klappa, Chairman of the Board, President and Chief Executive Officer and Director -- Principal Executive Officer	February 28, 2008
/s/ALLEN L. LEVERETT Allen L. Leverett, Executive Vice President and Chief Financial Officer -- Principal Financial Officer	February 28, 2008
/s/STEPHEN P. DICKSON Stephen P. Dickson, Vice President and Controller -- Principal Accounting Officer	February 28, 2008
/s/JOHN F. AHEARNE John F. Ahearne, Director	February 28, 2008
/s/JOHN F. BERGSTROM John F. Bergstrom, Director	February 28, 2008
/s/BARBARA L. BOWLES Barbara L. Bowles, Director	February 28, 2008
/s/PATRICIA W. CHADWICK Patricia W. Chadwick, Director	February 28, 2008
/s/ROBERT A. CORNOG Robert A. Cornog, Director	February 28, 2008

/s/CURT S. CULVER Curt S. Culver, Director	February 28, 2008
/s/THOMAS J. FISCHER Thomas J. Fischer, Director	February 28, 2008
/s/ULICE PAYNE, JR. Ulice Payne, Jr., Director	February 28, 2008
/s/FREDERICK P. STRATTON, JR. Frederick P. Stratton, Jr., Director	February 28, 2008

WISCONSIN ENERGY CORPORATION
(Commission File No. 001-09057)

EXHIBIT INDEX
to
Annual Report on Form 10-K
For the year ended December 31, 2007

The following exhibits are filed or furnished with or incorporated by reference in the report with respect to Wisconsin Energy Corporation. (An asterisk (*) indicates incorporation by reference pursuant to Exchange Act Rule 12b-32.)

Number		Exhibit
2	Plan of Acquisition, Reorganization, Arrangement, Liquidation or Succession	
	2.1*	Asset Sale Agreement by and among Wisconsin Electric Power Company, FPL Energy Point Beach, LLC, as Buyer, and FPL Group Capital Inc., as Buyer's Parent, dated December 19, 2006 (the "Asset Sale Agreement"). (Exhibit 2.1 to Wisconsin Energy Corporation's 12/31/06 Form 10-K.)
	2.2*	Letter Agreement between Wisconsin Electric Power Company and FPL Energy Point Beach, LLC, dated May 24, 2007, which effectively amends the Asset Sale Agreement. (Exhibit 2.1 to Wisconsin Energy Corporation's 06/30/07 Form 10-Q.)
	2.3*	Letter Agreement between Wisconsin Electric Power Company, FPL Energy Point Beach, LLC and FPL Group Capital, Inc., dated

September 28, 2007, which amends the Asset Sale Agreement. (Exhibit 2.3 to Wisconsin Energy Corporation's 09/28/07 Form 8-K).

3	Articles of Incorporation and By-laws	
	3.1*	Restated Articles of Incorporation of Wisconsin Energy Corporation, as amended and restated effective June 12, 1995. (Exhibit (3)-1 to Wisconsin Energy Corporation's 06/30/95 Form 10-Q.)
	3.2*	Bylaws of Wisconsin Energy Corporation, as amended to May 5, 2005. (Exhibit 3.2(b) to Wisconsin Energy Corporation's 12/31/04 Form 10-K.)
4	Instruments defining the rights of security holders, including indentures	
	4.1*	Reference is made to Article III of the Restated Articles of Incorporation and the Bylaws of Wisconsin Energy Corporation. (Exhibits 3.1 and 3.2 herein.)
	4.2*	Replacement Capital Covenant, dated May 11, 2007, by Wisconsin Energy Corporation for the benefit of certain debtholders named therein. (Exhibit 4.2 to Wisconsin Energy Corporation's 05/08/07 Form 8-K.)

Indentures and Securities Resolutions:

4.3*	Indenture for Debt Securities of Wisconsin Electric (the "Wisconsin Electric Indenture"), dated December 1, 1995. (Exhibit (4)-1 under File No. 1-1245, Wisconsin Electric's 12/31/95 Form 10-K.)
4.4*	Securities Resolution No. 1 of Wisconsin Electric under the Wisconsin Electric Indenture, dated December 5, 1995. (Exhibit (4)-2 under File No. 1-1245, Wisconsin Electric's 12/31/95 Form 10-K.)
4.5*	Securities Resolution No. 2 of Wisconsin Electric under the Wisconsin Electric Indenture, dated November 12, 1996. (Exhibit 4.44 to Wisconsin Energy Corporation's 12/31/96 Form 10-K.)
4.6*	Securities Resolution No. 3 of Wisconsin Electric under the Wisconsin Electric Indenture, dated May 27, 1998. (Exhibit (4)-1 under File No. 1-1245, Wisconsin Electric's 06/30/98 Form 10-Q.)
4.7*	Securities Resolution No. 4 of Wisconsin Electric under the Wisconsin Electric Indenture, dated November 30, 1999. (Exhibit 4.46 under File No. 1-1245, Wisconsin Energy Corporation's/Wisconsin Electric's 12/31/99 Form 10-K.)

4.8*	Securities Resolution No. 5 of Wisconsin Electric under the Wisconsin Electric Indenture, dated as of May 1, 2003. (Exhibit 4.47 filed with Post-Effective Amendment No. 1 to Wisconsin Electric's Registration Statement on Form S-3 (File No. 333-101054), filed May 6, 2003.)
4.9*	Securities Resolution No. 6 of Wisconsin Electric under the Wisconsin Electric Indenture, dated as of November 17, 2004. (Exhibit 4.48 filed with Post-Effective Amendment No. 1 to Wisconsin Electric's Registration Statement on Form S-3 (File No. 333-113414), filed November 23, 2004.)
4.10*	Securities Resolution No. 7 of Wisconsin Electric under the Wisconsin Electric Indenture, dated as of November 2, 2006. (Exhibit 4.1 to Wisconsin Electric's 11/02/06 Form 8-K.)
4.11*	Indenture for Debt Securities of Wisconsin Energy (the "Wisconsin Energy Indenture"), dated as of March 15, 1999. (Exhibit 4.46 to Wisconsin Energy Corporation's 03/25/99 Form 8-K.)
4.12*	Securities Resolution No. 1 of Wisconsin Energy under the Wisconsin Energy Indenture, dated as of March 16, 1999. (Exhibit 4.47 to Wisconsin Energy Corporation's 03/25/99 Form 8-K.)
4.13*	Securities Resolution No. 2 of Wisconsin Energy under the Wisconsin Energy Indenture, dated as of March 23, 2001. (Exhibit 4.1 to Wisconsin Energy Corporation's 03/31/01 Form 10-Q.)
4.14*	Securities Resolution No. 3 of Wisconsin Energy under the Wisconsin Energy Indenture, dated as of November 13, 2001. (Exhibit 4.52 to Wisconsin Energy Corporation's 12/31/01 Form 10-K.)

4.15*	Securities Resolution No. 4 of Wisconsin Energy under the Wisconsin Energy Indenture, dated as of March 17, 2003. (Exhibit 4.12 filed with Post-Effective Amendment No. 1 to Wisconsin Energy Corporation's Registration Statement on Form S-3 (File No. 333-69592), filed March 20, 2003.)
4.16*	Securities Resolution No. 5 of Wisconsin Energy under the Wisconsin Energy Indenture, dated as of May 8, 2007. (Exhibit 4.1 to Wisconsin Energy Corporation's 05/08/07 Form 8-K.)
	Certain agreements and instruments with respect to long-term debt not exceeding 10 percent of the total assets of the Registrant and its subsidiaries on a consolidated basis have been omitted as permitted by related instructions. The Registrant agrees pursuant to Item 601(b)(4) of Regulation S-K to furnish to the Securities and Exchange Commission, upon request, a copy of all such agreements and

instruments.

10 Material Contracts

10.1*	Stock Purchase Agreement among Pentair, Inc., WICOR, Inc. and Wisconsin Energy Corporation, dated February 3, 2004 ("Stock Purchase Agreement"). (Exhibit 2.1 to Wisconsin Energy Corporation's 06/30/04 Form 10-Q.)
10.2*	Amendment to the Stock Purchase Agreement dated July 28, 2004. (Exhibit 2.2 to Wisconsin Energy Corporation's 06/30/04 Form 10-Q.)
10.3*	Membership Interest Purchase Agreement between CET Two, LLC and Tenaska Power Fund L.P., dated as of March 24, 2005 (the "Membership Purchase Agreement"). (Exhibit 10.1 to Wisconsin Energy Corporation's 03/31/05 Form 10-Q.)
10.4*	First Amendment to the Membership Purchase Agreement dated as of May 31, 2005. (Exhibit 10.1 to Wisconsin Energy Corporation's 06/30/05 Form 10-Q.)
10.5*	Credit Agreement, dated as of April 6, 2006, among Wisconsin Energy Corporation, as Borrower, the Lenders identified therein, and JPMorgan Chase Bank, N.A., as Administrative Agent and Fronting Bank. (Exhibit 10.1 to Wisconsin Energy Corporation's 03/31/06 Form 10-Q.)
10.6*	Credit Agreement, dated as of March 30, 2006, among Wisconsin Electric Power Company, as Borrower, the Lenders identified therein, and U.S. Bank National Association, as Administrative Agent and Fronting Bank. (Exhibit 10.2 to Wisconsin Energy Corporation's 03/31/06 Form 10-Q.)
10.7*	Credit Agreement, dated as of March 30, 2006, among Wisconsin Gas LLC, as Borrower, the Lenders identified therein, Citibank, N.A., as Administrative Agent, and U.S. Bank National Association, as Fronting Bank. (Exhibit 10.3 to Wisconsin Energy Corporation's 03/31/06 Form 10-Q.)
10.8*	Supplemental Executive Retirement Plan of Wisconsin Energy Corporation, as amended and restated as of April 1, 2004. (Exhibit 10.4 to Wisconsin Energy Corporation's 06/30/04 Form 10-Q.)** See Note.

10.9*

	Service Agreement, dated April 25, 2000, between Wisconsin Electric Power Company and Wisconsin Gas Company (n/k/a Wisconsin Gas LLC). (Exhibit 10.32 to Wisconsin Energy Corporation's 12/31/00 Form 10-K.)
10.10*	Executive Deferred Compensation Plan of Wisconsin Energy Corporation, as amended and restated as of July 23, 2004 (including amendments approved effective as of November 2, 2005). (Exhibit 10.2 to Wisconsin Energy Corporation's 09/30/05 Form 10-Q.)** See Note.
10.11*	Directors' Deferred Compensation Plan of Wisconsin Energy Corporation, as amended and restated as of May 1, 2004. (Exhibit 10.3 to Wisconsin Energy Corporation's 06/30/04 Form 10-Q.) ** See Note.
10.12*	Amended and Restated Wisconsin Energy Corporation Special Executive Severance Policy, effective as of April 26, 2000. (Exhibit 10.3 to Wisconsin Energy Corporation's 03/31/00 Form 10-Q.)** See Note.
10.13*	Short-Term Performance Plan of Wisconsin Energy Corporation effective January 1, 1992, as amended and restated as of August 15, 2000. (Exhibit 10.12 to Wisconsin Energy Corporation's 12/31/00 Form 10-K.)** See Note.
10.14*	Amended and Restated Wisconsin Energy Corporation Executive Severance Policy, effective as of April 26, 2000. (Exhibit 10.4 to Wisconsin Energy Corporation's 03/31/00 Form 10-Q.)** See Note.
10.15*	Service Agreement, dated December 29, 2000, between Wisconsin Electric Power Company and American Transmission Company LLC. (Exhibit 10.33 to Wisconsin Energy Corporation's 12/31/00 Form 10-K.)
10.16	Restated Non-Qualified Trust Agreement by and between Wisconsin Energy Corporation and The Northern Trust Company dated February 11, 2004, regarding trust established to provide a source of funds to assist in meeting of the liabilities under various nonqualified deferred compensation plans made between Wisconsin Energy Corporation or its subsidiaries and various plan participants.** See Note.
10.17	Base Salaries of Named Executive Officers of the Registrant.** See Note.
10.18*	Employment arrangement with Charles R. Cole, effective August 1, 1999. (Exhibit 10.3 to Wisconsin Energy Corporation's 12/31/00 Form 10-K.)** See Note.
10.19*	

	Employment arrangement with Larry Salustro, effective December 12, 1997. (Exhibit 10.7 to Wisconsin Energy Corporation's 12/31/00 Form 10-K.)** See Note.
10.20*	Affiliated Interest Agreement (Service Agreement), dated December 12, 2002, by and among Wisconsin Energy Corporation and its affiliates. (Exhibit 10.14 to Wisconsin Energy Corporation's 12/31/02 Form 10-K.)
10.21*	Amended and Restated Senior Officer Employment and Non-Compete Agreement between Wisconsin Energy Corporation and Gale E. Klappa, effective October 22, 2003, amended as of December 3, 2003. (Exhibit 10.21 to Wisconsin Energy Corporation's 12/31/03 Form 10-K.)** See Note.

10.22*	Senior Officer Employment and Non-Compete Agreement between Wisconsin Energy Corporation and Allen L. Leverett, effective July 1, 2003. (Exhibit 10.3 to Wisconsin Energy Corporation's 06/30/03 Form 10-Q.)** See Note.
10.23*	Senior Officer Employment and Non-Compete Agreement between Wisconsin Energy Corporation and Rick Kuester, effective October 13, 2003. (Exhibit 10.3 to Wisconsin Energy Corporation's 09/30/03 Form 10-Q.)** See Note.
10.24*	Letter Agreement by and between Wisconsin Energy Corporation and James C. Fleming, dated as of November 23, 2005, which became effective January 3, 2006. (Exhibit 10.31 to Wisconsin Energy Corporation's 12/31/05
	Form 10-K.)** See Note.
10.25	Amended and Restated Senior Officer, Change in Control, Severance and Non-Compete Agreement between Wisconsin Energy Corporation and Kristine A. Rappé, dated as of December 19, 2007.** See Note.
10.26*	Supplemental Pension Benefit agreement between Wisconsin Energy Corporation and Stephen Dickson, effective May 23, 2001. (Exhibit 10.1 to Wisconsin Energy Corporation's 06/30/01 Form 10-Q.)** See Note.
10.27*	Forms of Stock Option Agreements under 1993 Omnibus Stock Incentive Plan. (Exhibit 10.5 to Wisconsin Energy Corporation's 12/31/95 Form 10-K. Updated as Exhibit 10.1(a) and 10.1(b) to Wisconsin Energy Corporation's 03/31/00

	Form 10-Q.)** See Note.
10.28*	1998 Revised forms of award agreements under 1993 Omnibus Stock Incentive Plan, as amended, for non-qualified stock option awards to non-employee directors, restricted stock awards and option awards. (Exhibit 10.11 to Wisconsin Energy Corporation's 12/31/98 Form 10-K.)** See Note.
10.29*	Form of Nonstatutory Stock Option Agreement under the WICOR, Inc. 1994 Long-Term Performance Plan. (Exhibit 4.2 to WICOR, Inc.'s Registration Statement on Form S-8 (Reg. No. 33-55755).)** See Note.
10.30*	Form of Nonstatutory Stock Option Agreement for February 2000 Grants of Options under the WICOR, Inc. 1994 Long-Term Performance Plan. (Exhibit 4.5 to Wisconsin Energy Corporation's Registration Statement on Form S-8 (Reg. No. 333-35798).)** See Note.
10.31*	2001 Revised forms of award agreements under 1993 Omnibus Stock Incentive Plan, as amended, for restricted stock awards, incentive stock option awards and non-qualified stock option awards. (Exhibit 10.3 to Wisconsin Energy Corporation's 03/31/01 Form 10-Q.)** See Note.
10.32*	1993 Omnibus Stock Incentive Plan, as amended and restated, as approved by the stockholders at the 2001 annual meeting of stockholders. (Appendix A to Wisconsin Energy Corporation's Proxy Statement dated March 20, 2001 for the 2001 annual meeting of stockholders.)** See Note.
10.33*	2005 Terms and Conditions Governing Non-Qualified Stock Option Award under 1993 Omnibus Stock Incentive Plan, as amended. (Exhibit 10.1 to Wisconsin Energy Corporation's 12/28/04 Form 8-K.)** See Note.

10.34*	Terms and Conditions Governing Non-Qualified Stock Option Award under the 1993 Omnibus Stock Incentive Plan, as amended. (Exhibit 10.1 to Wisconsin Energy Corporation's 09/30/07 Form 10-Q.)** See Note.

10.35*	Wisconsin Gas Company (n/k/a Wisconsin Gas LLC) Supplemental Retirement Income Program. (Exhibit 10.8 to Wisconsin Gas Company's 12/31/98 Form 10-K (File No. 001-07530).)** See Note.
10.36*	WICOR, Inc. 1994 Long-Term Performance Plan, as amended. (Exhibit 10.1 to WICOR, Inc.'s 06/30/98 Form 10-Q (File No. 001-07951).)** See Note.
10.37*	Form of Performance Share Agreement under 1993 Omnibus Stock Incentive Plan, as amended. (Exhibit 10.42 to Wisconsin Energy Corporation's 12/31/03 Form 10-K.)** See Note.
10.38	Wisconsin Energy Corporation Performance Unit Plan, as amended and restated. ** See Note.
10.39*	Form of Award of Performance Units under the Wisconsin Energy Corporation Performance Unit Plan. (Exhibit 10.2 to Wisconsin Energy Corporation's 12/06/04 Form 8-K.)** See Note.
10.40*	Port Washington I Facility Lease Agreement between Port Washington Generating Station, LLC, as Lessor, and Wisconsin Electric Power Company, as Lessee, dated as of May 28, 2003. (Exhibit 10.7 to Wisconsin Electric Power Company's 06/30/03 Form 10-Q (File No. 001-01245).)
10.41*	Port Washington II Facility Lease Agreement between Port Washington Generating Station, LLC, as Lessor, and Wisconsin Electric Power Company, as Lessee, dated as of May 28, 2003. (Exhibit 10.8 to Wisconsin Electric Power Company's 06/30/03 Form 10-Q (File No. 001-01245).)
10.42*	Elm Road I Facility Lease Agreement between Elm Road Generating Station Supercritical, LLC, as Lessor, and Wisconsin Electric Power Company, as Lessee, dated as of November 9, 2004. (Exhibit 10.56 to Wisconsin Energy Corporation's 12/31/04 Form 10-K.)
10.43*	

	Elm Road II Facility Lease Agreement between Elm Road Generating Station Supercritical, LLC, as Lessor, and Wisconsin Electric Power Company, as Lessee, dated as of November 9, 2004. (Exhibit 10.57 to Wisconsin Energy Corporation's 12/31/04 Form 10-K.)
10.44*	Point Beach Nuclear Plant Power Purchase Agreement between FPL Energy Point Beach, LLC and Wisconsin Electric Power Company, dated as of December 19, 2006 (the "PPA"). (Exhibit 10.46(a) to Wisconsin Energy Corporation's 12/31/06 Form 10-K.)***
10.45	Letter Agreement between Wisconsin Electric Power Company and FPL Energy Point Beach, LLC dated October 31, 2007, which amends the PPA.

Note: Two asterisks (**) identify management contracts and executive compensation plans or arrangements required to be filed as exhibits pursuant to Item 15(b) of Form 10-K.

*** Wisconsin Energy requested confidential treatment of certain portions of this document pursuant to an application for confidential treatment sent to the SEC. Wisconsin Energy omitted such portions from the document upon filing with its 12/31/06 Form 10-K and filed it separately with the SEC.

21 Subsidiaries of the registrant

21.1	Subsidiaries of Wisconsin Energy Corporation.

23 Consents of experts and counsel

23.1	Deloitte & Touche LLP -- Milwaukee, WI, Consent of Independent Registered Public Accounting Firm.

31 Rule 13a-14(a) / 15d-14(a) Certifications

31.1	Certification Pursuant to Rule 13a-14(a) or 15d-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification Pursuant to Rule 13a-14(a) or 15d-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32	Section 1350 Certifications	
	32.1	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
	32.2	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.