WISCONSIN ENERGY CORP
Form 10-K
February 28, 2007
Table of Contents

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, 2006

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

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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, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer x Accelerated filer ¨ Non-accelerated filer ¨.

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 $4.7 billion based upon the reported closing price of such securities as of June 30, 2006.

Indicate the number of shares outstanding of each of the registrant s classes of common stock, as of the latest practicable date (January 31, 2007):

Common Stock, $.01 Par Value, 116,951,992 shares outstanding

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 3, 2007, are incorporated by reference into Part III hereof.

Table of Contents

WISCONSIN ENERGY CORPORATION

FORM 10-K REPORT FOR THE YEAR ENDED DECEMBER 31, 2006

TABLE OF CONTENTS

Table of Contents

TABLE OF CONTENTS (Cont d)

Table of Contents

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
Guardian	Guardian Pipeline L.L.C.
Minergy	Minergy Corp.
Minergy Neenah	Minergy Neenah, LLC
NMC	Nuclear Management Company, LLC
WECC	Wisconsin Energy Capital Corporation
WICOR	Wicor, Inc.
Wispark	Wispark LLC
Wisvest	Wisvest Corporation
Federal and State Regulatory Agencies	
DOA	Wisconsin Department of Administration
DOE	United States Department of Energy
EPA	United States Environmental Protection Agency
FAA	Federal Aviation Administration
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
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule

CAVR	Clean Air Visibility Rule
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act

Table of Contents

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

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
FPL	FPL Group, Inc.
FTRs	Financial Transmission Rights
GCRM	Gas Cost Recovery Mechanism
GDP	Gross Domestic Product
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 Midwest Market	MISO bid-based energy market
Moody s	Moody s Investor Service
NEIL	Nuclear Electric Insurance Limited
PJM	PJM Interconnection, L.L.C.
PTF	Power the Future
PUHCA 1935	Public Utility Holding Company Act of 1935, as amended
PUHCA 2005	Public Utility Holding Company Act of 2005
RTO	Regional Transmission Organizations
S&P	Standard & Poors Corporation
Yellowcake	Uranium Concentrate

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)
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

Table of Contents

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.

FSP	FASB Staff Position
GAAP	Generally Accepted Accounting Principles
NOLs	Net Operating Loss Carryforwards
OPEB	Other Post-Retirement Employee Benefits
PCAOB	Public Company Accounting Oversight Board
SAB	Staff Accounting Bulletin
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
SAB 108	Process of Quantifying Financial Statement Misstatements
SFAS 34	Capitalization of Interest Cost
SFAS 71	Accounting for the Effects of Certain Types of Regulation
SFAS 87	Employers Accounting for Pensions
SFAS 88	Employers Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits
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 132R	Employers Disclosures about Pensions and Other Postretirement Benefits (Revised 2003)
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 148	Accounting for Stock-Based Compensation - Transition and Disclosure
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

Table of Contents

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

Certain statements contained in this report and other documents or oral presentations are forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. 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 completion of construction projects, regulatory matters, fuel costs, sources of electric energy supply, the proposed sale of Point Beach, 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, intends, may, object 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, nuclear 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; nuclear or environmental incidents; resolution of used nuclear fuel storage and disposal issues; electric transmission or gas pipeline system constraints; unanticipated organizational structure or key personnel changes; collective bargaining agreements with union employees or work stoppages; inflation rates; or demographic and economic factors affecting utility service territories or operating environment.

Regulatory factors such as unanticipated changes in rate-setting policies or procedures; unanticipated changes in regulatory accounting policies and practices; industry restructuring initiatives; transmission or distribution system operation and/or administration initiatives; recovery of costs of previous investments made under traditional regulation; recovery of costs associated with adoption of changed accounting standards; required changes in facilities or operations to reduce the risks or impacts of potential terrorist activities; required approvals for new construction; changes in the United States Nuclear Regulatory Commission s regulations related to Point Beach Nuclear Plant or a permanent repository for used nuclear fuel; changes in the regulations of the United States Environmental Protection Agency as well as the Wisconsin Department of Natural Resources, the Michigan Department of Natural Resources or the Michigan Department of Environmental Quality, including but not limited to regulations relating to the release of emissions from fossil-fueled power plants such as carbon dioxide, sulfur dioxide, nitrogen oxide, small particulates or mercury, water quality and lead paint; and regulations relating to the intake and discharge of water; the siting approval process for new generation and transmission facilities; recovery of costs associated with implementation of a bid-based energy market; or changes in the regulations from the Wisconsin Department of Natural Resources related to the siting approval process for new pipeline construction.

The changing electric and gas utility environment as market-based forces replace strict industry regulation and other competitors enter the electric and gas markets resulting in increased wholesale and retail competition.

Unanticipated operational and/or financial consequences related to implementation of the Midwest Independent Transmission System Operator, Inc. bid-based energy market that started in April 2005.

Consolidation of the industry as a result of the combination and acquisition of utilities in the Midwest, nationally and globally as a result of the repeal of the Public Utility Holding Company Act of 1935 or otherwise.

Factors related to the proposed sale of our Point Beach Nuclear Plant including receipt of the necessary approvals by various regulatory agencies, including the United States Nuclear Regulatory Commission, the Public Service Commission of Wisconsin, the Michigan Public Service Commission and the Federal Energy

Regulatory Commission, for the transaction; and our ability to retain the assets for the benefit of customers in the non-qualified decommissioning trust.

Factors which impede execution of our *Power the Future* strategy, including receipt of necessary state and federal regulatory approvals, timely and successful resolution of legal challenges, local opposition to siting of new generating facilities, construction risks, including 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.

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.

Changes in social attitudes regarding the utility and power industries.

Customer business conditions including demand for their products or services and supply of labor and material used in creating their products and services.

The cost and other effects of legal and administrative proceedings, settlements, investigations and 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 security ratings.

Federal, state or local legislative factors such as changes in tax laws or rates; changes in trade, monetary and fiscal policies, laws and regulations; electric and gas industry restructuring initiatives; changes in the Price-Anderson Act; changes in environmental laws and regulations; or changes in allocation of energy assistance, including state public benefits funds.

Implementation of the Energy Policy Act of 2005 and the effect of state level proceedings and the development of regulations by federal and other agencies, including the Federal Energy Regulatory Commission.

Authoritative generally accepted accounting principle or policy changes from such standard setting bodies as the Financial Accounting Standards Board, the Securities and Exchange Commission and the Public Company Accounting Oversight Board.

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

Possible risks associated with non-utility operations and investments, such as: general economic conditions; competition; operating risks; dependence upon certain suppliers and customers; the cyclical nature of property values that could affect real estate investments; unanticipated changes in environmental or energy regulations; and risks associated with minority investments, where there is a limited ability to control the development, management or operation of the project.

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 Securities and Exchange Commission filings or in other publicly disseminated written documents.

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

Table of Contents

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 and We Power.

Utility Energy Segment: Our utility energy segment consists of: Wisconsin Electric, Wisconsin Gas and Edison Sault. We serve approximately 1,125,200 electric customers in Wisconsin and the Upper Peninsula of Michigan. We have approximately 1,041,400 gas customers in Wisconsin, 460 steam customers in metro Milwaukee, Wisconsin, and 3,000 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: Effective September 27, 2006, we sold 100% of our membership interests in Minergy Neenah. Previously Minergy Neenah operations were included in Corporate and Other. We sold our Calumet facility, which was part of our non-utility energy segment, effective May 31, 2005. Effective July 31, 2004, we sold our manufacturing segment.

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 Midwest Market 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.

Table of Contents

ITEM 1. BUSINESS - (Cont d)

Electric Sales

Our electric energy sales to all classes of customers, excluding intercompany sales between Edison Sault and Wisconsin Electric, totaled approximately 31.9 million MWh during 2006 and approximately 32.5 million MWh during 2005. Edison Sault did not have any significant MWh sales during 2005 and 2006 to Wisconsin Electric. Approximately 0.4 million MWh sales of Wisconsin Electric during 2005 and 2006 were to Edison Sault. We had approximately 1,125,200 electric customers at December 31, 2006 and 1,115,300 electric customers at December 31, 2005.

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 Midwest Market.

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% to 1.5% over the next five years. This estimate excludes the mine contract (see Legal Matters under Factors Affecting Results, Liquidity and Capital Resources in Item 7), 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 currently has special negotiated power-sales contracts with these mines that expire in December 2007. The combined electric energy sales to the two mines accounted for 6.2% and 7.1% of our total electric utility energy sales during 2006 and 2005, respectively. In 2005, the mines notified us that they were disputing certain billings and they have placed the disputed amounts in escrow. We have notified the mines that we believe that they have failed to comply with certain notification provisions related to annual production as specified within the contract. Arbitration hearings related to this matter are scheduled for August 2007. Although it is currently uncertain, we anticipate that we will provide power to the mines under the terms of one or more regulated tariffs to be approved by the MPSC beginning January 1, 2008. For further information, see Legal Matters under Factors Affecting Results, Liquidity and Capital Resources in Item 7.

Sales to Wholesale Customers: During 2006, 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 34 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 2006. Wholesale sales accounted for approximately 9.7% of our total electric energy sales and 5.1% of total electric operating revenues during 2006, compared with 8.8% of total electric energy sales and 4.9% of total electric operating revenues during 2005.

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, we reached our all-time electric peak demand obligation of 6,505 MW on July 31, 2006. 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 ReliabilityFirst Corporation, a successor council encompassing most of the East Central Area Reliability Council and Mid-Atlantic Area Council and a portion of MAIN. ReliabilityFirst Corporation has not yet established guidelines in this area but members are expected to adhere to the guidelines of their predecessor councils until new guidelines are established. Wisconsin Electric must also adhere to PSCW guidelines requiring an 18% planning reserve margin and we expect to be in

compliance with

Table of Contents

ITEM 1. BUSINESS - (Cont d)

ReliabilityFirst Corporation guidelines when they are established. The MPSC has not established guidelines in this area.

We had adequate capacity to meet all of our firm electric load obligations during 2006 and expect to have adequate capacity to meet all of our firm obligations during 2007. For additional information, see Factors Affecting Results, Liquidity and Capital Resources in Item 7.

Electric Supply

The table below indicates our sources of electric energy supply as a percentage of sales, for the three years ended December 31, 2006, as well as an estimate for 2007. This information excludes any impact of the proposed sale of Point Beach.

	Estimate	Actual		
	2007	2006	2005	2004
Coal	59.9%	54.7%	57.6%	60.8%
Nuclear	24.5%	25.3%	20.0%	23.7%
Hydroelectric	1.7%	1.4%	1.6%	1.7%
Natural gas	6.6%	4.1%	2.9%	0.2%
Net Generation	92.7%	85.5%	82.1%	86.4%
Purchased Power	7.3%	14.5%	17.9%	13.6%
Total	100.0%	100.0%	100.0%	100.0%

Our PTF strategy, which is discussed further in Item 7, includes the addition of 2,320 MW of generating capacity through 2010. Our PTF strategy includes two 545 MW natural gas units at an existing site in Port Washington, Wisconsin. The first unit, which has a current dependable capability of 575 MW, was placed into service in July 2005. The second unit is expected to be placed in service in 2008. We have begun construction of two 615 MW coal units (of which we will own approximately a 515 MW share of each unit) in Oak Creek, Wisconsin adjacent to the site of Wisconsin Electric s existing Oak Creek Power Plant. We anticipate that the first coal unit will be placed in service in 2009, followed by the second unit in 2010.

We believe that our PTF strategy will allow us to better manage the mix of fuels used to generate electricity for our customers. We believe that it is in the best interests of our customers to provide a diverse fuel mix that is expected to maintain a stable, reliable and affordable energy supply in our service territory.

Our net generation, including PWGS 1, totaled 28.9 million MWh during 2006 compared with 28.2 million MWh during 2005 and 29.2 million MWh during 2004. Net generation as a percent of our total electric energy supply increased in 2006 due to the availability of the PWGS 1 for the entire year and one fewer scheduled nuclear outage in 2006 versus 2005.

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

	2006	2005	2004
Coal	$ 18.30	$ 14.74	$ 14.18
Nuclear	$ 5.23	$ 5.06	$ 4.68
Natural Gas - Combined Cycle	$ 66.30	$ 84.77	

Natural Gas - Peaking Units	$ 136.24	$ 125.67	$ 95.16
Purchased Power	$ 47.67	$ 53.59	$ 36.17

We use natural gas to fuel our peaking units that are designed to run for short durations. The PWGS natural gas-fired units that are part of the PTF strategy are combined cycle facilities that are designed to run for longer durations and at a lower operating cost as compared to a peaking unit.

Table of Contents

ITEM 1. BUSINESS - (Cont d)

Historically, the fuel costs for coal and nuclear generation have been under long-term contracts, which helped with price stability. In 2006, we entered into new 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 in the last three years which has been reflected in the form of fuel surcharges on rail transportation. Coal price increases in 2006 were more pronounced due to the expiration of certain favorable long-term contracts at the end of 2005. Based on current market conditions, we expect our coal and transportation costs to continue to increase, but at a more modest rate than we experienced in 2006.

The costs for natural gas and purchased power, which is primarily natural gas-fired, are more 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 for natural gas. Beginning in late 2003 and concurrent with the approval of 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 2006, 2005 and 2004 average costs of natural gas and purchased power shown above.

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

	Dependable Capability in MW (a)		
	2006	2005	2004
Coal	3,334	3,334	3,334
Nuclear	1,036	1,036	1,036
Natural Gas/Oil (b)	1,755	1,713	1,168
Hydro	84	84	84
Total	6,209	6,167	5,622

(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) Approximately 50% of the Natural Gas/Oil units are dual fueled. The dual fuel 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. The increase in 2006 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.

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 2007, 96.2% of our projected coal requirements of 12.2 million tons will be under contracts which are not tied to 2007 market pricing fluctuations. We do not anticipate any problem in procuring our remaining 2007 coal requirements. Our coal-fired generation consists of six operating plants with a dependable capability of approximately 3,334 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. 2007	0.1
Dec. 2008	4,850.0
Dec. 2009	6,500.0

Table of Contents

ITEM 1. BUSINESS - (Cont d)

Coal Deliveries: Approximately 85.7% of our 2007 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 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 Environmental Compliance below.

Nuclear Generation

Point Beach: Wisconsin Electric owns two 518 MW electric generating units at Point Beach in Two Rivers, Wisconsin. The operating licenses for Point Beach will expire in October 2030 for Unit 1 and in March 2033 for Unit 2. In December 2006, we announced that Wisconsin Electric had reached a definitive agreement to sell Point Beach to an affiliate of FPL. Under the agreement, FPL will purchase the plant, its nuclear fuel and associated inventories for approximately $998 million, subject to closing price adjustments, and it will also assume the obligation to decommission the plant. We also entered into a long-term power purchase agreement to purchase all of the existing capacity and energy of the plant, which will become effective upon closing of the sale. This transaction is subject to regulatory review and approval and we anticipate it will close during the third quarter of 2007. If and when the sale is completed (or earlier if an interim operating agreement with FPL is activated by us), Point Beach s operating licenses would transfer from NMC to FPL. Until the transaction is completed, Wisconsin Electric continues to own Point Beach and retains exclusive rights to the energy generated by the plant, as well as financial responsibility for the safe operation, maintenance and decommissioning of Point Beach. For additional information concerning Point Beach, see Factors Affecting Results, Liquidity and Capital Resources Nuclear Operations in Item 7 and Note I Nuclear Operations in the Notes to Consolidated Financial Statements in Item 8.

Nuclear Management Company: NMC, owned by our affiliate, WEC Nuclear Corporation and the affiliates of two other unaffiliated investor-owned utilities in the region, operates Point Beach. NMC currently operates six nuclear generating units at four sites in the states of Wisconsin, Minnesota and Michigan with a total combined generating capacity of approximately 3,500 MW. One of the other two unaffiliated investor-owned utilities has announced the planned sale of their unit.

Nuclear Fuel Supply: Wisconsin Electric purchases Yellowcake and contracts for its conversion, enrichment and fabrication. There have been numerous events in the nuclear fuel supply market that have affected the price of uranium concentrates, conversion service and enrichment services. The price of the fuel commodities has risen steadily since the fourth quarter of 2003 and we anticipate that the price will continue to rise due to current demand exceeding current supply. NMC is continually monitoring the nuclear fuel commodities market to assess current and future commodity pricing and adjusting purchasing strategies to address changes in the market conditions. Wisconsin Electric maintains title to the nuclear fuel until fabricated fuel assemblies are delivered to Point Beach; it is then sold to and leased back from the Wisconsin Electric Fuel Trust. For further information concerning this nuclear fuel lease, see Note K Long-Term Debt in the Notes to Consolidated Financial Statements in Item 8.

Uranium Requirements: Wisconsin Electric requires approximately 400,000 to 450,000 pounds of Yellowcake to refuel a generating unit at Point Beach. Point Beach has staggered fuel cycles that are expected to average approximately 18 months in duration. The supply of Yellowcake for these refuelings is currently provided through one long-term contract, which supplies 100% of the annual requirements through 2009. Contract negotiations through NMC are currently underway that would supply approximately 60% of the Point Beach requirements from 2010 to 2016.

Conversion: Wisconsin Electric had conversion services supply from a share of an NMC fleet contract for conversion services and four spot purchase contracts to meet 100% of its conversion requirements for 2006. In

Table of Contents

ITEM 1. BUSINESS - (Cont d)

2006, an additional NMC fleet contract for conversion services was signed to supply approximately 100% of the Point Beach requirements through 2010 and approximately 10% of the 2011 requirements.

Enrichment: Wisconsin Electric effectively has three contracts through NMC that provide for 100% of the required enrichment services for Point Beach through the year 2009 and approximately 70% of the enrichment services requirements through 2013.

Fabrication: Fabrication of fuel assemblies from enriched uranium for Point Beach is covered under a contract with Westinghouse Electric Company, LLC. The current contract for fabrication services is through 2010 for Unit 1 and 2013 for Unit 2.

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.

Nuclear Decommissioning: Wisconsin Electric provides for costs associated with the eventual decommissioning of Point Beach through the use of external trust funds. Payments to these funds, together with investment results, brought the balance in the funds at December 31, 2006 to approximately $881.6 million. For additional information regarding decommissioning, including the impact of the proposed sale of Point Beach, see Factors Affecting Results, Liquidity and Capital Resources Nuclear Operations in Item 7 and Note I Nuclear Operations in the Notes to Consolidated Financial Statements in Item 8.

Nuclear Plant Insurance: For information regarding nuclear plant insurance, see Note I Nuclear 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, 2006. 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 Point Beach and 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 has a dependable capability of approximately 280 MW at December 31, 2006. 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.

Hydroelectric 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, 2006. 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.

Table of Contents

ITEM 1. BUSINESS - (Cont d)

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. Marys 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.

Purchase Power Commitments

We enter into short and long-term purchase power commitments to meet a portion of our anticipated electric energy supply needs. The following table identifies our purchase power commitments at December 31, 2006 with unaffiliated parties for the next five years:

Year	MW Under Purchase Power Commitments
2007	1,148
2008	698
2009	580
2010	580
2011	550

The majority of these purchase power 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.

We have entered into a long-term power purchase agreement with FPL that is contingent upon the sale of Point Beach. This agreement allows us to receive all the existing capacity and energy of the Point Beach units. We will have the unilateral option, subject to PSCW direction, to select a term for the power purchase agreement of either (i) an estimated 23 years for Unit 1 and 26 years for Unit 2, or (ii) 16 years for Unit 1 and 17 years for Unit 2. This agreement is subject to approval by various regulatory authorities.

Electric Transmission and Energy Markets

American Transmission Company: ATC owns, maintains, monitors and operates electric utility transmission 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. As of February 1, 2002, operational control of ATC s transmission system was transferred to MISO, and Wisconsin Electric and Edison Sault are non-transmission owning members and customers of MISO.

Table of Contents

ITEM 1. BUSINESS - (Cont d)

We owned approximately 29.4% and 33.5% of ATC as of December 31, 2006 and 2005. Our ownership has decreased from December 31, 2005 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 a bid-based energy market, the MISO Midwest Market, which was implemented on April 1, 2005. For further information on MISO and the MISO Midwest Market, see Factors Affecting Results, Liquidity and Capital Resources in Item 7.

Renewable Electric Energy

Our PTF strategy includes a commitment 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. Act 141 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.

Table of Contents

ITEM 1. BUSINESS - (Cont d)

Electric Utility Operating Statistics

The following table shows certain electric utility operating statistics from 2002 to 2006 for electric operating revenues, MWh sales and customer data.

SELECTED CONSOLIDATED ELECTRIC UTILITY OPERATING DATA

Year Ended December 31	2006	2005	2004	2003	2002
Operating Revenues (Millions)					
Residential	$ 883.2	$ 827.6	$ 731.3	$ 715.5	$ 703.0
Small Commercial/Industrial	814.8	746.1	668.0	642.0	606.3
Large Commercial/Industrial	647.5	602.4	549.9	519.3	483.1
Other - Retail/Municipal	97.3	112.6	90.7	84.9	77.7
Resale - Utilities	51.2	21.3	24.6	24.0	18.1
Other Operating Revenues	35.4	39.7	34.5	27.9	22.6
Total Operating Revenues	$ 2,529.4	$ 2,349.7	$ 2,099.0	$ 2,013.6	$ 1,910.8
MWh Sales (Thousands)					
Residential	8,322.7	8,562.7	8,053.9	8,099.3	8,310.9
Small Commercial/Industrial	9,142.2	9,192.7	8,840.4	8,740.6	8,719.5
Large Commercial/Industrial	11,173.1	11,687.5	11,686.4	11,401.8	11,129.6
Other - Retail/Municipal	2,227.5	2,713.6	2,405.5	2,225.9	2,051.9
Resale - Utilities	1,025.7	313.7	662.2	715.8	650.7
Total Sales	31,891.2	32,470.2	31,648.4	31,183.4	30,862.6
Customers - End of Year (Thousands)					
Residential	1,009.7	1,001.7	992.3	980.5	969.4
Small Commercial/Industrial	112.3	110.5	108.7	106.9	106.2
Large Commercial/Industrial	0.7	0.7	0.7	0.7	0.7
Other	2.5	2.4	2.4	2.4	2.4
Total Customers	1,125.2	1,115.3	1,104.1	1,090.5	1,078.7
Customers - Average (Thousands)	1,120.5	1,109.7	1,096.8	1,083.1	1,072.6
Degree Days (a)					
Heating (6,663 Normal)	6,043	6,628	6,663	7,063	6,551
Cooling (716 Normal)	723	949	442	606	897

(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.

Table of Contents

ITEM 1. BUSINESS - (Cont d)

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 2,028.9 million therms during 2006, a 6.5% decrease compared with 2005. At December 31, 2006, we were transporting gas for approximately 1,400 customers who purchased gas directly from other suppliers. Transported gas accounted for approximately 42% of the total volumes delivered during 2006, 41% during 2005, and 37% during 2004. We had approximately 1,041,400 gas customers at December 31, 2006, an increase of approximately 1.1% since December 31, 2005.

Our maximum daily send-out during 2006 was 1,406,429 Dth on February 18, 2006. A Dth is equivalent to ten therms or one million Btu.

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 energy supply 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, 2011 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. Many 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

Table of Contents

ITEM 1. BUSINESS - (Cont d)

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 and withdraw it in the winter months. As a result, we can contract for less long-line pipeline capacity 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 2006, we entered 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 ratepayers, 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 2006, 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) 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 Pipeline: 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 their 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 October 2006, in connection with the Guardian extension, we filed applications with the PSCW to construct approximately 27 miles of pipeline laterals to connect

our gas distribution system to the proposed Guardian extension. The Guardian extension is projected to be operational in November 2008.

Table of Contents

ITEM 1. BUSINESS - (Cont d)

Gas Utility Operating Statistics

The following table shows certain gas utility operating statistics from 2002 to 2006 for gas operating revenues, therms delivered and customer data.

SELECTED CONSOLIDATED GAS UTILITY OPERATING DATA

Year Ended December 31	2006	2005	2004	2003	2002
Operating Revenues (Millions)					
Residential	$ 862.4	$ 898.9	$ 798.6	$ 769.3	$ 591.0
Commercial/Industrial	443.8	465.4	396.5	386.0	279.7
Interruptible	17.0	20.4	17.0	16.9	12.6
Total Retail Gas Sales	1,323.2	1,384.7	1,212.1	1,172.2	883.3
Transported Gas	47.8	46.3	41.4	36.6	39.4
Other Operating Revenues	48.9	(13.5)	(1.1)	17.3	(4.6)
Total Operating Revenues	$ 1,419.9	$ 1,417.5	$ 1,252.4	$ 1,226.1	$ 918.1
Therms Delivered (Millions)					
Residential	727.9	791.0	809.9	853.7	817.1
Commercial/Industrial	435.9	460.7	464.0	492.5	463.1
Interruptible	21.3	23.4	24.7	27.5	29.4
Total Retail Gas Sales	1,185.1	1,275.1	1,298.6	1,373.7	1,309.6
Transported Gas	843.8	893.7	769.5	797.5	811.7
Total Therms Delivered	2,028.9	2,168.8	2,068.1	2,171.2	2,121.3
Customers - End of Year (Thousands)					
Residential	951.0	940.7	927.4	912.0	896.8
Commercial/Industrial	88.9	87.5	85.9	84.7	83.8
Interruptible	0.1	0.1	0.1	0.1	0.1
Transported Gas	1.4	1.4	1.4	1.4	1.4
Total Customers	1,041.4	1,029.7	1,014.8	998.2	982.1
Customers - Average (Thousands)	1,033.3	1,019.8	1,003.5	986.7	973.2
Degree Days (a)					
Heating (6,663 Normal)	6,043	6,628	6,663	7,063	6,551

(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 2006, the steam utility had $27.2 million of operating revenues from the sale of 2,812 million pounds of

Table of Contents

ITEM 1. BUSINESS - (Cont d)

steam compared with $23.5 million of operating revenues from the sale of 2,908 million pounds of steam during 2005. As of December 31, 2006 and 2005, steam was used by approximately 460 customers 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, 2006, the water utility served approximately 3,000 water customers in the suburban Milwaukee area compared with approximately 2,800 customers at December 31, 2005. Wisconsin Gas also provides contract services to local municipalities and businesses within its service territory for water system repair and maintenance. During 2006, the water utility had $2.5 million of operating revenues compared with $2.3 million of operating revenues during 2005.

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 $616.8 million. 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 our subsidiary 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 proposed as part of our PTF strategy, 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 lease this capacity to Wisconsin Electric. At December 31, 2006, we had approximately $888.5 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 Corporation

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, 2006, Wisvest had $10.0 million of operating revenues from continuing operations compared with $9.5 million of operating revenues from continuing operations during 2005. We have divested substantially all of Wisvest s assets. As of December 31, 2006, Wisvest s sole operating asset and investment is Wisvest Thermal Energy Services, which provides chilled water services to the Milwaukee Regional Medical Center.

Table of Contents

ITEM 1. BUSINESS - (Cont d)

OTHER NON-UTILITY OPERATIONS

Minergy Corp.

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 Factors Affecting Results, Liquidity and Capital Resources in Item 7 and 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, 2006 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 risks of environmental liabilities. The first commercial GlassPack® facility has been 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, 2006, Wispark has reduced its overall holdings from $373.1 million to $61.5 million. During the twelve months ended December 31, 2006, Wispark had $1.1 million of consolidated operating revenues compared with $18.6 million during 2005.

Wispark has developed several business parks primarily in southeastern Wisconsin. Wispark s flagship development, the 1,600-acre LakeView Corporate Park located near Kenosha, Wisconsin 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.

In December 2004, Wispark entered into a joint venture with a major industrial development company whereby Wispark contributed land in its LakeView and GrandView Corporate parks valued at approximately $40.0 million to the joint venture in return for approximately $20.8 million in cash, future development fees and a 36% interest in the joint venture, which includes land contributed by our joint venture partner.

Other Non-Utility Subsidiaries

Other non-utility subsidiaries primarily include:

Wisconsin Energy Capital Corporation: WECC engages in investing and financing activities. Activities include advances to affiliated companies and investments in partnerships that developed low- and moderate-income housing projects.

WEC Nuclear Corporation: WEC Nuclear Corporation has a 33.3% ownership interest in NMC. As discussed above, in December 2006, we announced that we had reached a definitive agreement to sell Point Beach to an affiliate of FPL. If and when the sale is completed (or earlier if an interim operating agreement with FPL is activated by us), NMC would transfer Point Beach s operating licenses to the buyer and we would withdraw from NMC and terminate our relationship with it. We would have to pay a termination fee of approximately $12 million to withdraw from NMC and we would have to write-off our investment in NMC that is approximately $5 million at December 31, 2006.

Table of Contents

ITEM 1. BUSINESS - (Cont d)

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 PUCHA 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 part of the 1999-2001 biennial state budget, 1999 Wisconsin Act 9. 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, 2006.

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 would be entirely exempt from the definition of non-utility property for this purpose. The remaining cost of our PTF plan 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 PUCHA 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 PUCHA 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, repeals PUHCA 1935 making electric utility industry consolidation more possible, authorizes FERC to review proposed mergers and the acquisition of generation facilities, changes FERC regulatory scheme applicable to qualifying co-generation facilities and modifies 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 will establish mandatory electric reliability standards, replacing the current voluntary standards developed by the North American Electric Reliability Corporation, and will have 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

Table of Contents

ITEM 1. BUSINESS - (Cont d)

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, 2006.

	2006		2005		2004	
	Amount	Percent	Amount	Percent	Amount	Percent
	(Millions of Dollars)					
Wisconsin - Retail						
Electric	$ 2,222.4	55.9%	$ 2,049.7	54.0%	$ 1,830.6	54.2%
Gas	1,419.9	35.7%	1,417.5	37.4%	1,252.4	37.1%
Steam and Water	29.7	0.7%	25.8	0.7%	24.0	0.7%
Total	3,672.0	92.3%	3,493.0	92.1%	3,107.0	92.0%
Michigan - Retail						
Electric	177.8	4.5%	184.1	4.9%	170.2	5.0%
FERC - Wholesale						
Electric	129.2	3.2%	115.9	3.0%	98.2	3.0%
Total Utility Operating Revenues	$ 3,979.0	100.0%	$ 3,793.0	100.0%	$ 3,375.4	100.0%

For information concerning the implementation of full electric retail competition in the State of Michigan effective January 1, 2002, see Factors Affecting Results, Liquidity and Capital Resources in Item 7.

Operation and construction relating to Point Beach are subject to regulation by the NRC. 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. Act 141 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 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 is a holding company subsidiary of Wisconsin Energy and 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.

Table of Contents

ITEM 1. BUSINESS - (Cont d)

In 2005, President Bush signed into law the Energy Policy Act. The Energy Policy Act and corresponding rules developed by FERC require 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 for FERC 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. In July 2005, PWGS 1 became operational and the sale of test power ceased. 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 $79 million in 2006 compared with $153 million in 2005. Expenditures incurred during 2006 primarily included costs associated with the installation of pollution abatement facilities at Wisconsin Electric s power plants. These expenditures are expected to approximate $39 million during 2007, 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 $49 million during 2006 and $40 million during 2005.

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.

Table of Contents

ITEM 1. BUSINESS - (Cont d)

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 new units. Currently there is a temporary cap installed and 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.

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, 2006, we had the following number of employees:

	Total Employees	Represented Employees
Utility Energy Segment		
Wisconsin Electric	4,597	3,170
Wisconsin Gas	572	433
Edison Sault	60	42
Total	5,229	3,645
Non-Utility Energy Segment	43	
Other	31	
Total Employees	5,303	3,645

Table of Contents

ITEM 1. BUSINESS - (Cont d)

The employees represented under labor agreements were with the following bargaining units as of December 31, 2006.

	Number of Employees	Expiration Date of Current Labor Agreement
Wisconsin Electric		
Local 2150 of International Brotherhood of Electrical Workers	2,337	August 15, 2007
Local 317 of International Union of Operating Engineers (a)	456	September 30, 2006
Local 12005 of United Steel Workers of America (b)	165	November 1, 2008
Local 510 of International Brotherhood of Electrical Workers	161	April 30, 2007
Local 2-0111 of Paper, Allied- Industrial Chemical & Energy Workers International Union (b)	51	November 3, 2008
Total Wisconsin Electric	3,170	
Wisconsin Gas		
Local 2150 of International Brotherhood of Electrical Workers	105	August 15, 2007
Local 2-0018 of Paper, Allied- Industrial Chemical & Energy Workers International Union (b)	152	December 31, 2010
Local 2-0018-1 of Paper, Allied- Industrial Chemical & Energy Workers International Union (b)	168	December 31, 2010
Local 2-0018-2 of Paper, Allied- Industrial Chemical & Energy Workers International Union (b)	8	February 29, 2008
Total Wisconsin Gas	433	
Edison Sault		
Local 13547 of United Steel Workers of America	42	October 22, 2007
Total Edison Sault	42	
Total Employees	3,645	

(a) Labor agreement was effective October 1, 2003 through September 30, 2006. It remains in effect since settlement has not yet been reached as of December 31, 2006.

(b) 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

Table of Contents

ITEM 1A. RISK FACTORS - (Cont d)

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. 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 or other amounts, which could materially adversely effect 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, 7% 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 prudent costs and expenses and to maintain our current authorized rates of return.

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. A second 545 MW natural gas-fired generating unit is currently being constructed.

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 and changes in applicable law or regulations, adverse interpretation or enforcement of permit conditions, laws and regulations by the permitting agencies, 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 recovered from Wisconsin Electric. 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 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.

As required by the Energy Policy Act, FERC developed new rules to implement certain provisions of the Energy Policy Act. Pursuant to these new rules, Wisconsin Electric requested FERC authorization in November 2006 to lease from We Power the three PTF units that are currently being constructed by We Power. We received authorization from FERC for these leases in December 2006.

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 carbon dioxide, sulfur dioxide, nitrogen oxide, 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.

Table of Contents

ITEM 1A. RISK FACTORS - (Cont d)

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. 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.

Ownership and operation of nuclear generating units involve inherent risks that may result in substantial costs and liabilities.

We own two 518 MW nuclear electric generating units at Point Beach. The units are operated by NMC, a joint venture of Wisconsin Energy and affiliates of other unaffiliated utilities. During 2006, our nuclear generating units provided approximately 25.3% of our net electric energy supply. In December 2006, we announced that we had reached a definitive agreement to sell our nuclear plant to an affiliate of FPL. This transaction is subject to regulatory review and approval and we anticipate it will close during the third quarter of 2007. Until the transaction is approved, Wisconsin Electric continues to own Point Beach and retains exclusive rights to the energy generated by the plant, as well as financial responsibility for the safe operation, maintenance and decommissioning of Point Beach.

Our nuclear facilities are subject to environmental, health and financial risks, including: handling of nuclear materials, on-site storage of spent nuclear fuel and the current lack of a long-term solution for disposal of materials; mechanical or structural problems; lapses in maintenance procedures; human errors in the operation of the reactors or safety systems; limitations on the amounts and types of insurance coverage commercially available; the continued ability of NMC to effectively manage and operate our nuclear facilities; and uncertainties regarding our ability to maintain adequate reserves for decommissioning the units. While we have no reason to anticipate a serious nuclear incident at our units, if an incident were to occur, it could result in substantial costs to us that may significantly exceed the amount of our insurance coverage and reserves.

The NRC has broad authority to impose licensing and safety related requirements for the operation of nuclear generating facilities. In the event of non-compliance, the NRC has the authority to impose fines or shut down a unit, or both, until compliance is achieved. Further, in the event of a major incident at a nuclear facility anywhere in the world, the NRC could limit or prohibit the operation or licensing of any domestic nuclear unit.

As a result of the September 11, 2001 terrorist attacks, the NRC and the industry have been strengthening security at nuclear power plants. Increased security measures and other safety requirements could require us to make substantial capital expenditures at our nuclear generating units.

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

Our electric generation and gas transportation facilities, including our nuclear facilities and the facilities of third parties on which we rely, could be targets of terrorist activities. A terrorist attack on our facilities could result in a full or partial disruption of our ability to generate, transmit, transport 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 adversely affect our results of operations and financial condition.

Table of Contents

ITEM 1A. RISK FACTORS - (Cont d)

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 significantly because the supply of natural gas in recent years 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 s electric operations burn 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, and 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 these fuels as well.

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 exposes 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 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 MWh purchases through other potentially higher cost generating resources in the MISO Midwest Market. 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 generation outages can result in additional maintenance expenses as well as incremental replacement power costs.

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 decline, we may experience reduced demand for electricity or natural gas that could result in decreased earnings and cash flow. In addition,

regional economic conditions also impact our collections of accounts receivable.

Table of Contents

ITEM 1A. RISK FACTORS - (Cont d)

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. 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 ratings downgrade, prevailing market conditions or other factors, our results of operations and financial condition could be materially adversely affected.

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, you may be deprived of opportunities to sell some or all of your 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 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

Table of Contents

ITEM 1A. RISK FACTORS - (Cont d)

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 Midwest Market on April 1, 2005. The MISO Midwest Market 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 Midwest Market, we are required to follow MISO s instructions when dispatching generating units to support MISO s responsibility for maintaining stability of the transmission system.

Additionally, the MISO Midwest Market subjects us to additional costs primarily associated with constraints in the transmission system. MISO implemented the LMP system, a market-based platform for valuing transmission congestion. The LMP system includes the ability to mitigate or eliminate congestion charges through the use of FTRs. FTRs are allocated to market participants by MISO for a twelve month period. There can be no assurance that we will be granted an adequate level of FTRs in the future to avoid material unhedged congestion charges. As allowed by the PSCW, unhedged congestion charges are deferred and we expect to recover these costs in future rates, subject to review and approval of the PSCW.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

Table of Contents

ITEM 2. PROPERTIES

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

As of December 31, 2006, we owned or leased the following generating stations with dependable capabilities during 2006 as indicated.

Name	Fuel	No. of Generating Units	Dependable Capability in MW (a) July
Steam Plants			
Point Beach	Nuclear	2	1,026
Oak Creek	Coal	4	1,135
Presque Isle	Coal	9	618
Pleasant Prairie	Coal	2	1,224
Valley	Coal	2	267
Edgewater 5 (b)	Coal	1	105
Milwaukee County	Coal	3	10
Total Steam Plants		23	4,385
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
Other Combustion Turbines & Diesel	Gas/Oil	6	43
Total System		150	6,217

(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.

We have a power purchase contract with an unaffiliated independent power producer. The contract is for 236 MW of firm capacity from a gas-fired cogeneration facility that expires in 2022.

As of December 31, 2006, we operated approximately 23,304 pole-miles of overhead distribution lines and 22,440 miles of underground distribution cable, as well as approximately 387 distribution substations and 287,958 line transformers. We own various office buildings and service centers throughout our electric utility service areas.

As of December 31, 2006, our gas distribution system included approximately 19,900 miles of distribution and transmission mains connected at 179 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 4,400 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

Table of Contents

ITEM 2. PROPERTIES - (Cont d)

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, 2006, 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. 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 Corporation: Wisvest owns a chilled water production and distribution facility located in Milwaukee County, Wisconsin.

Wispark LLC: As of December 31, 2006, 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 and PrairieWood Corporate Park in Kenosha County; and GrandView Business Park in Racine County. 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. Wispark sold a number of other property holdings during 2006, including two low-income housing developments owned jointly with WECC.

Minergy Corp.: Minergy owns a GlassPack® facility in Winneconne, Wisconsin. In September 2006, Minergy sold its Minergy Neenah facility. 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.

Wisconsin Energy Capital Corporation: WECC, in combination with Wispark, owns a low-income housing development located in Neenah, Wisconsin. WECC had other investments, which were sold during 2006.

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 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

Table of Contents

ITEM 3. LEGAL PROCEEDINGS - (Cont d)

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 2007. 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 through the Settlement Agreement. 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 - Proposed 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.

On February 26, 2004, a Wisconsin jury awarded $850,000 to a dairy farmer who alleged that Wisconsin Electric s distribution system caused damages to his livestock. Wisconsin Electric appealed this decision. In April 2006, the Wisconsin Court of Appeals affirmed the jury s verdict against Wisconsin Electric. Wisconsin Electric paid $1.3 million with interest and costs to the plaintiffs in this suit.

In May 2005, a stray voltage lawsuit was filed against Wisconsin Electric. We do not believe the lawsuit has merit and we will vigorously defend the case. The trial for this matter is scheduled to begin in April 2007. This claim against Wisconsin Electric is not expected to 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.

Electromagnetic Fields: Claims have been made or threatened against electric utilities across the country for bodily injury, disease or other damages allegedly caused or aggravated by exposure to electromagnetic fields associated with electric transmission and distribution lines. Results of scientific studies conducted to date have not established the existence of a causal connection between electromagnetic fields and any adverse health affects. Wisconsin Electric and Edison Sault believe that their facilities are constructed and operated in accordance with applicable legal requirements and standards. Currently, there are no cases pending or threatened against Wisconsin Electric or Edison Sault with respect to damage caused by electromagnetic fields.

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

Table of Contents

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 2006.

EXECUTIVE OFFICERS OF THE REGISTRANT

The names, ages at December 31, 2006 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 56.

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 Wisconsin Energy Corporation, Wisconsin Electric Power Company and Wisconsin Gas LLC since 2003.

Charles R. Cole. Age 60.

Wisconsin Electric Power Company Senior Vice President since 2001.

Wisconsin Gas LLC Senior Vice President since July 2004.

Stephen P. Dickson. Age 46.

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 61.

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 56.

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.

Table of Contents

EXECUTIVE OFFICERS OF THE REGISTRANT - (Cont d)

Allen L. Leverett. Age 40.

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.

Southern Company Services, Inc. Vice President and Treasurer from 2000 to 2002. Southern Company Services is also an affiliate of The Southern Company.

Kristine Rappé. Age 50.

Wisconsin Energy Corporation Senior Vice President and Chief Administrative Officer since May 2004. Corporate Secretary from 2001 to August 2004. Vice President from 2003 to April 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 2001 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.

Larry Salustro. Age 59.

Wisconsin Energy Corporation Executive Vice President since May 2004. General Counsel from 2000 to March 2006. Senior Vice President from 2000 to April 2004.

Wisconsin Electric Power Company Executive Vice President since May 2004. General Counsel from 2000 to March 2006. Senior Vice President from 2000 to April 2004.

Wisconsin Gas LLC Executive Vice President since May 2004. General Counsel from 2000 to March 2006. Senior Vice President from 2000 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, 2006, based upon the number of Wisconsin Energy Corporation stockholder accounts (including accounts in our dividend reinvestment and stock purchase plan), we had approximately 54,000 registered stockholders.

COMMON STOCK LISTING AND TRADING

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

Table of Contents

ITEM 5. MARKET FOR REGISTRANT S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES (Cont d)

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 18, 2007, our Board of Directors announced that it increased our common stock quarterly dividend rate by 8.7%, to $0.25 per share. With the increase, the new dividend is equivalent to an annual rate of $1.00 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:

	2006			2005		
Quarter	High	Low	Dividend	High	Low	Dividend
First	$ 42.35	$ 38.92	$ 0.23	$ 36.12	$ 33.35	$ 0.22
Second	$ 40.91	$ 38.16	0.23	$ 39.31	$ 34.20	0.22
Third	$ 43.79	$ 39.75	0.23	$ 40.48	$ 37.32	0.22
Fourth	$ 48.70	$ 43.25	0.23	$ 40.83	$ 36.49	0.22
Year	$ 48.70	$ 38.16	$ 0.92	$ 40.83	$ 33.35	$ 0.88

ISSUER PURCHASES OF EQUITY SECURITIES

2006	Total Number of Shares Purchased (a)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (Millions of Dollars)
October 1- October 31	885	$ 44.66		
November 1- November 30	5,864	$ 39.42		
December 1- December 31	719	$ 40.23		
Total	7,468	$ 40.12		

(a) This table does not include shares purchased by independent agents to satisfy obligations under our employee benefit plans and stock purchase and dividend reinvestment plan. All shares reported during the quarter were surrendered by employees to satisfy tax withholding

obligations upon vesting of restricted stock.

Table of Contents

ITEM 6. SELECTED FINANCIAL DATA

WISCONSIN ENERGY CORPORATION

CONSOLIDATED SELECTED FINANCIAL AND STATISTICAL DATA

Financial	2006	2005	2004	2003	2002
Year Ended December 31					
Net income - Continuing Operations (Millions)	$ 312.5	$ 303.6	$ 219.6	$ 201.3	$ 135.9
Earnings per share - Continuing Operations					
Basic	$ 2.67	$ 2.59	$ 1.87	$ 1.72	$ 1.18
Diluted	$ 2.64	$ 2.56	$ 1.84	$ 1.70	$ 1.17
Dividends per share of common stock	$ 0.92	$ 0.88	$ 0.83	$ 0.80	$ 0.80
Common Stock Price - High During Year	$ 48.70	$ 40.83	$ 34.60	$ 33.68	$ 26.48
Common Stock Price - Low During Year	$ 38.16	$ 33.35	$ 29.50	$ 22.56	$ 20.17
Operating revenues (Millions)					
Utility energy	$ 3,979.0	$ 3,793.0	$ 3,375.4	$ 3,263.9	$ 2,852.1
Non-utility energy	69.1	40.0	19.9	12.3	165.0
Other including eliminations	(51.7)	(17.5)	10.8	5.9	15.6
Total operating revenues	$ 3,996.4	$ 3,815.5	$ 3,406.1	$ 3,282.1	$ 3,032.7
At December 31 (Millions)					
Total assets	$ 11,130.2	$ 10,462.0	$ 9,565.4	$ 10,014.5	$ 9,465.9
Long-term debt (including current maturities), capital lease obligations and mandatorily redeemable trust preferred securities	$ 3,370.1	$ 3,527.0	$ 3,340.5	$ 3,736.7	$ 3,266.6

CONSOLIDATED SELECTED QUARTERLY FINANCIAL DATA (Unaudited)

	(Millions of Dollars, Except Per Share Amounts) (a)			
	March		June	
Three Months Ended	2006	2005	2006	2005
Operating revenues	$ 1,247.0	$ 1,094.7	$ 814.4	$ 788.5
Operating income	191.6	166.8	107.1	89.9
Income from Continuing Operations	104.4	90.0	59.7	56.8
Income (loss) from Discontinued Operations	1.3	(0.1)	3.2	5.2
Total Net Income	$ 105.7	$ 89.9	$ 62.9	$ 62.0
Earnings per share of common stock (basic) (b)				
Continuing operations	$ 0.89	$ 0.77	$ 0.51	$ 0.49
Discontinued operations	0.01		0.03	0.04
Total earnings per share (basic)	$ 0.90	$ 0.77	$ 0.54	$ 0.53
Earnings per share of common stock (diluted) (b)				
Continuing operations	$ 0.88	$ 0.76	$ 0.50	$ 0.48
Discontinued operations	0.01		0.03	0.04

Total earnings per share (diluted)	$ 0.89	$ 0.76	$ 0.53	$ 0.52

Three Months Ended	September 2006	September 2005	December 2006	December 2005
Operating revenues	$ 839.8	$ 797.3	$ 1,095.2	$ 1,135.0
Operating income	131.2	128.4	138.6	177.8
Income from Continuing Operations	70.8	65.8	77.6	91.0
Income (loss) from Discontinued Operations		0.4	(0.6)	(0.4)
Total Net Income	$ 70.8	$ 66.2	$ 77.0	$ 90.6
Earnings per share of common stock (basic) (b)				
Continuing operations	$ 0.61	$ 0.57	$ 0.66	$ 0.77
Discontinued operations				
Total earnings per share (basic)	$ 0.61	$ 0.57	$ 0.66	$ 0.77
Earnings per share of common stock (diluted) (b)				
Continuing operations	$ 0.60	$ 0.56	$ 0.65	$ 0.77
Discontinued operations				
Total earnings per share (diluted)	$ 0.60	$ 0.56	$ 0.65	$ 0.77

(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.

Table of Contents

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. 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.

Proposed Sale of Point Beach: In February 2006, we announced that we were undertaking a formal review regarding our options for the ownership and operation of Point Beach. These options included (1) continued operation by NMC, (2) having a third party other than NMC operate the plant, (3) a return to in-house operations by Wisconsin Electric, (4) sale of the plant and (5) a partial sale of the plant with us retaining a minority interest in the Plant. Under this fifth option, the new majority owner would operate the plant. After a thorough review of the various options, we concluded that a full sale of the plant was in our best interest and in the best interest of our customers.

In December 2006, we announced that Wisconsin Electric had signed a definitive agreement with an affiliate of FPL to sell Point Beach for approximately $998 million, subject to closing price adjustments. Under the terms of the sale, the buyer would assume the obligation to decommission the plant, and we would transfer assets in a qualified trust for decommissioning. We would retain assets in a non-qualified decommissioning trust. Wisconsin Electric also entered into a long-term power purchase agreement to purchase all of the existing capacity and energy of the plant. This long-term power purchase agreement will become effective upon the closing of the sale. If and when the sale is completed (or earlier if an interim operating agreement with FPL is activated by us), NMC would transfer Point Beach s operating licenses to FPL and our relationship with NMC would be terminated. The sale of the plant and the long-term power purchase agreement are subject to review and approval by various regulatory agencies including the NRC, PSCW, MPSC and FERC. We anticipate closing the sale during the third quarter of 2007.

We, along with FPL, have made a request to the IRS for a Private Letter Ruling (PLR) related to the transfer of the qualified decommissioning trust assets. We are requesting permission to withdraw excess funds from the qualified trust without receiving unfavorable tax treatment. If we receive a favorable PLR, we would use the excess funds for the direct benefit of our customers. If we do not receive a favorable PLR, then the purchase price would be adjusted

Table of Contents

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont d)

upward by approximately $50 million based on information as of December 31, 2006. We are unable to predict how or even if the IRS may rule on our request for a PLR.

If the sale is approved, we expect to receive after-tax cash proceeds exceeding $1.0 billion from the sale and the liquidation of the decommissioning trust assets. The net sales proceeds are expected to exceed our cost in the nuclear plant, and, absent regulatory treatment, we would expect to record a gain on the sale. However, we have made a filing with PSCW to defer any gain (net of transaction related costs) as a regulatory liability that would be applied to the benefit of our customers in future rate proceedings. As such, we do not expect the sale of the plant, if approved, to have a material impact on our 2007 earnings.

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 the 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 plan to add new coal-fired and natural gas-fired generating capacity to the state s power portfolio which would allow us to maintain approximately the same fuel mix as exists today. PWGS 1 and 2 and OC 1 and 2 have a total output of 2,320 MW, of which we expect to own 2,120 MW. As part of our PTF strategy, we plan to (1) invest approximately $2.6 billion in 2,120 MW of new natural gas-fired and coal-fired generating capacity at existing sites; (2) upgrade our existing electric generating facilities; and (3) invest in upgrades of our existing energy distribution system.

Subsequent to our February 2001 filing, the state 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, 2006, 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 in early 2006, and procured all of the major components for PWGS 2. Construction is underway and PWGS 2 is expected to be operational in 2008.

Table of Contents

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont d)

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 in November 2005.

Received approval from the PSCW for various leases between We Power and Wisconsin Electric.

We expect to finance the majority of our PTF strategy with internally generated cash and debt financings. We expect our debt to total capital ratio, as measured by the debt rating agencies will not exceed 61.5% through our PTF construction period. 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. You can find additional information regarding risks associated with the PTF strategy, as well as the regulatory process and specific regulatory approvals, in 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. Since 2000, we have received total proceeds of approximately $2.2 billion from the divestiture of assets as follows:

Proceeds from divestitures: (Millions of Dollars)	**2000 -2006**
Manufacturing	$ 857.0
Non-Utility Energy	616.8
Real Estate	462.2
Transmission	119.8
Guardian	38.5
Other	77.3
Total	$ 2,171.6

Table of Contents

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont d)

RESULTS OF OPERATIONS

CONSOLIDATED EARNINGS

The following table compares our operating income by business segment and our net income for 2006, 2005 and 2004.

Wisconsin Energy Corporation	2006	2005	2004
	(Millions of Dollars)		
Utility Energy	$ 532.8	$ 542.4	$ 528.6
Non-Utility Energy	43.1	19.5	4.6
Corporate and Other	(7.4)	1.0	(3.2)
Total Operating Income	568.5	562.9	530.0
Equity in Earnings of Transmission Affiliate	38.6	34.6	30.1
Other Income and Deductions, net	53.1	28.7	(14.3)
Interest Expense	172.7	173.4	193.4
Income From Continuing Operations Before Income Taxes	487.5	452.8	352.4
Income Taxes	175.0	149.2	132.8
Income From Continuing Operations	312.5	303.6	219.6
Income From Discontinued Operations, Net of Tax (a)	3.9	5.1	86.8
Net Income	$ 316.4	$ 308.7	$ 306.4
Diluted Earnings Per Share			
Continuing Operation	$ 2.64	$ 2.56	$ 1.84
Discontinued Operations	0.03	0.05	0.73
Total Diluted Earnings Per Share	$ 2.67	$ 2.61	$ 2.57

(a) Income from Discontinued Operations, Net of Tax includes: (1) Minergy Neenah, which we sold effective September 27, 2006, (2) the manufacturing segment, which we sold effective July 31, 2004 and (3) Calumet which we sold effective May 31, 2005. All periods reported in this table reflect these items as discontinued operations.

The following table identifies significant items that are included in our Diluted Earnings per Share from Continuing Operations.

	(Expense) Benefit		
	2006	2005	2004
Reduction of Tax Valuation Allowances	$ 0.05	$ 0.14	$
Voluntary Severance Program	$	$	($ 0.16)
Debt Redemption Costs	$	$	($ 0.13)

An analysis of contributions to operating income by segment and a more detailed analysis of results in 2006, 2005, and 2004 follow.

UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

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.

Table of Contents

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont d)

2005 vs. 2004: Our utility energy segment contributed $542.4 million of operating income during 2005 compared with $528.6 million of operating income during 2004. This increase primarily reflects favorable weather during the summer of 2005 and increased gas margins. Also, during 2004 we recorded severance costs under a voluntary severance program. The year to year increase in operating income was partially offset by an increase in our net under-recovered fuel position and higher operation and maintenance expenses during 2005. We had two scheduled refueling outages at our nuclear plant in 2005 in comparison to one scheduled refueling outage in 2004.

The following table summarizes our utility energy segment s operating income during 2006, 2005 and 2004.

Utility Energy Segment	2006	2005	2004
	(Millions of Dollars)		
Operating Revenues			
Electric	$ 2,529.4	$ 2,349.7	$ 2,099.0
Gas	1,419.9	1,417.5	1,252.4
Other	29.7	25.8	24.0
Total Operating Revenues	3,979.0	3,793.0	3,375.4
Fuel and Purchased Power	806.2	780.8	591.7
Cost of Gas Sold	1,018.3	1,047.3	890.9
Gross Margin	2,154.5	1,964.9	1,892.8
Other Operating Expenses			
Other Operation and Maintenance	1,211.1	1,010.4	963.0
Depreciation, Decommissioning and Amortization	314.0	324.1	315.5
Property and Revenue Taxes	96.6	88.0	85.7
Operating Income	$ 532.8	$ 542.4	$ 528.6

Table of Contents

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont d)

Electric Utility Gross Margin

The following table compares our electric utility gross margin during 2006 with similar information for 2005 and 2004, including a summary of electric operating revenues and electric sales by customer class.

	Electric Revenues and Gross Margin			Electric MWh Sales		
Electric Utility Operations	**2006**	**2005**	**2004**	**2006**	**2005**	**2004**
	(Millions of Dollars)			**(Thousands, Except Degree Days)**		
Customer Class						
Residential	$ 883.2	$ 827.6	$ 731.3	8,322.7	8,562.7	8,053.9
Small Commercial/Industrial	814.8	746.1	668.0	9,142.2	9,192.7	8,840.4
Large Commercial/Industrial	647.5	602.4	549.9	11,173.1	11,687.5	11,686.4
Other-Retail/Municipal	97.3	112.6	90.7	2,227.5	2,713.6	2,405.5
Resale-Utilities	51.2	21.3	24.6	1,025.7	313.7	662.2
Other Operating Revenues	35.4	39.7	34.5			
Total Electric Operating Revenues	$ 2,529.4	$ 2,349.7	$ 2,099.0	31,891.2	32,470.2	31,648.4
Fuel and Purchased Power						
Fuel	487.9	432.7	334.7			
Purchased Power	309.8	340.3	250.3			
Total Fuel and Purchased Power	797.7	773.0	585.0			
Total Electric Gross Margin	$ 1,731.7	$ 1,576.7	$ 1,514.0			
Weather Degree Days (a)						
Heating (6,663 Normal)				6,043	6,628	6,663
Cooling (716 Normal)				723	949	442

(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

2006 vs. 2005: Our electric utility operating revenues increased by $179.7 million, or 7.6%, when compared to 2005. We estimate that 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 utility operating revenues are expected to increase in 2007 primarily due to the impact of a full year of the January 2006 Wisconsin retail pricing increase and the expected implementation of increased wholesale rates, as well as the impacts of our fuel adjustment clause that are tied to our fuel and purchase power costs. During 2006, we reserved approximately $38 million of revenues associated with favorable recoveries of fuel and purchase power. 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.

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 largest customers, two iron ore mines, decreased 1.4%. Sales volumes in the Other Retail/Municipal class decreased approximately 18% 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

Table of Contents

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont d)

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.

2005 vs. 2004: During 2005, our total electric utility operating revenues increased by $250.7 million or 11.9% when compared with 2004 primarily due to favorable weather during the summer of 2005 and pricing increases.

During 2005, we estimate that pricing increases contributed an additional $145.8 million of revenues than in 2004. The most significant impact to rates was a March 2005 interim order received by Wisconsin Electric from the PSCW authorizing an annualized increase in electric rates of approximately $114.9 million due to the increased costs of fuel and purchased power. In November 2005, Wisconsin Electric received the final rate order, which authorized an additional $7.7 million of annual revenues. Additional orders impacting rates in 2005 were the May 2004 and May 2005 orders received by Wisconsin Electric from the PSCW authorizing annualized increases in electric rates of approximately $59.0 million and $59.7 million, respectively, primarily to cover construction costs associated with our PTF strategy.

Total electric sales increased by 2.6% between 2005 and 2004. Residential sales volumes increased 6.3% due to the favorable summer weather in 2005. Total sales volumes to commercial/industrial customers increased 1.7% between comparative periods. Sales volumes to commercial/industrial customers, excluding our largest customers, two iron ore mines, increased 2.3% due to the favorable weather during the summer of 2005. We estimate that weather increased our electric revenues by approximately $68.8 million during 2005 as compared to the prior year. As measured by cooling degree days, 2005 was 114.7% warmer than in 2004.

Sales volumes in the Resale-Utilities class decreased 52.6% primarily due to the reduced availability of base-load capacity for sale at competitive prices as a result of limited fuel supplies and outages. Sales volumes to municipal utilities, the Other Retail/Municipal customer class, increased 12.8% between the periods due to higher off-peak demand from lower margin municipal wholesale power customers.

Electric Fuel and Purchased Power Expenses

2006 vs. 2005: 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.

Our electric fuel and purchased power expenses in 2007 are expected to be impacted by the duration of the scheduled nuclear refueling outage in the first quarter of 2007; the timing and completion of the proposed sale of Point Beach; the price of purchased power; the increased cost of coal and related transportation; and changes in electric sales.

2005 vs. 2004: Gross fuel and purchased power costs for our electric utilities increased by a total of $260.8 million during 2005 when compared with 2004. During 2005, we deferred $72.8 million of fuel and purchased power costs which resulted in a net increase of fuel and purchased power expense of $188.0 million or 32.1% during 2005 when compared to 2004. The increase in fuel and purchased power expense was driven by a 2.6% increase in MWh sales and an increase in our average cost of fuel and purchased power from $18.48 per MWh in 2004 to $23.80 per MWh in 2005, or 28.8% between the comparative periods.

The increase in our average cost of fuel and purchased power was due primarily to (1) the reduced availability of nuclear generation due to scheduled refueling outages, (2) higher natural gas prices that increased the cost of power supplied by natural gas, (3) the impact of the implementation of the MISO Midwest Market in April 2005 and (4) limitations on coal supplies due to transportation shortfalls.

During 2005, we had two scheduled refueling outages at our nuclear plant and in 2004 we had one scheduled refueling outage. As a result, we had approximately 1,145,000 fewer MWh of nuclear generation in 2005. Our average fuel cost for nuclear generation is approximately $5 per

MWh, while the average energy cost for purchased

Table of Contents

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont d)

power was approximately $55 per MWh. We estimate that the reduction in nuclear generation resulted in approximately $57 million of increased fuel and purchased power costs in 2005 as compared to 2004. During the 2005 outages we replaced both reactor vessel heads resulting in longer outages. This work, along with other planned maintenance, lasted longer than originally expected due to delays. For more information regarding the scheduled refueling outages, see Factors Affecting Results, Liquidity and Capital Resources Nuclear Operations.

In 2005, we experienced significant increases in the cost of natural gas used in our own generating assets and in the price of purchased energy which is highly influenced by the price of natural gas. This increase was most significant in the last six months of 2005 due to market related factors including the hurricanes in the Gulf of Mexico. The average combined cost per MWh of purchased energy and natural gas fired units in 2005 was 47.7% higher than in 2004, increasing total cost by approximately $77.2 million.

In April 2005, we began participating in the MISO Midwest Market which fundamentally changed the way we dispatch our generating units and obtain purchased energy. As part of this new market, we are subject to new types of charges which, among other things, recognize the cost of transmission congestion, MWh losses and other costs associated with operating the generating units in an uneconomic fashion to support the MISO Midwest Market service territory. The State of Wisconsin has a constrained transmission system and we believe these constraints result in higher costs for us than in other parts of the MISO Midwest Market service territory. The incremental costs associated with the MISO Midwest Market charges identified above were approximately $28 million in 2005. For more information regarding MISO and the MISO Midwest Market, see Factors Affecting Results, Liquidity and Capital Resources Industry Restructuring and Competition Electric Transmission and Energy Markets.

Our 2005 operations were also adversely impacted by limitations on deliveries of coal supply due to the failure of our primary rail delivery supplier to deliver contracted quantities of coal to our units. The largest limitation was related to critical rail track maintenance in the Powder River basin. This, in turn, resulted in reduced coal deliveries of the coal which primarily serves our Oak Creek and Pleasant Prairie generating units from June through December 2005. In response to the reduced deliveries, we reduced generating output of these units during off-peak periods when replacement power prices were lower, purchased more expensive replacement power and took measures to purchase and transport higher cost coal in place of contracted supplies when it made economic sense to do so. We estimate that this increased our costs by approximately $52 million in 2005. For additional information on the decreased coal deliveries, see Factors Affecting Results, Liquidity and Capital Resources Market Risks and Other Significant Risks Commodity Prices.

Under the State of Wisconsin fuel rules, we are allowed to request recovery in fuel revenues if our projected fuel and purchased power costs exceed bands established by the PSCW. In March 2005, we received a rate order that allowed us to increase our annual revenues by $114.9 million (final order received in November 2005 for an annual increase of $122.6 million) due to increased fuel and purchased power costs. As provided under the Wisconsin rules, we are also allowed to request deferral for the costs associated with adverse events which materially impact fuel and purchased power costs which were not anticipated, or for which costs could not be reasonably estimated at the time of the fuel recovery request for consideration in future rate proceedings. During 2005, we deferred approximately $72.8 million of fuel and purchased power costs due to the extended outage at Point Beach Unit 2, the coal delivery problems and increased costs associated with the MISO Midwest Market. During 2005, we estimate that we under-recovered fuel and purchased power costs by $108.4 million before these deferred items. Adjusted for the allowed deferrals, our net under-recovered fuel and purchased power costs were approximately $35.6 million.

Table of Contents

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont d)

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 2006, 2005 and 2004.

Gas Utility Operations	2006	2005	2004
	(Millions of Dollars)		
Operating Revenues	$ 1,419.9	$ 1,417.5	$ 1,252.4
Cost of Gas Sold	1,018.3	1,047.3	890.9
Gross Margin	$ 401.6	$ 370.2	$ 361.5

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 2006, 2005 and 2004.

Gas Utility Operations	Gross Margin			Therm Deliveries		
	2006	2005	2004	2006	2005	2004
	(Millions of Dollars)			(Millions, Except Degree Days)		
Customer Class						
Residential	$ 255.0	$ 240.5	$ 238.0	727.9	791.0	809.9
Commercial/Industrial	86.0	72.9	71.9	435.9	460.7	464.0
Interruptible	2.0	1.8	1.8	21.3	23.4	24.7
Total Gas Sold	343.0	315.2	311.7	1,185.1	1,275.1	1,298.6
Transported Gas	51.3	48.5	43.8	843.8	893.7	769.5
Other Operating	7.3	6.5	6.0			
Total	$ 401.6	$ 370.2	$ 361.5	2,028.9	2,168.8	2,068.1
Weather - Degree Days (a)						
Heating (6,663 Normal)				6,043	6,628	6,663

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

2006 vs. 2005: Gas utility gross margin increased by $31.4 million or 8.5% between the comparative periods. The increase in gross margin is 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 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. We continue to see a reduction in normalized use of gas per customer which we believe is 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.

Table of Contents

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont d)

The gas utility gross margins are expected to increase in 2007 primarily due to the impact of a full year of the January 2006 pricing increases. In addition, 2007 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.

2005 vs. 2004: Gas utility gross margin increased by $8.7 million or 2.4% between the comparative periods. This increase reflects $6.5 million of price increases which reflects the full year s impact of a $25.9 million annual rate increase, which became effective in March 2004. Total therm deliveries were 4.9% higher during 2005 primarily due to increased transport gas deliveries of 124.2 million therms. Transport volumes increased between the comparative periods due to a higher amount of electric generation from natural gas within our service territory. A portion of these sales are eliminated in consolidation. Our margins on these transport gas volumes are significantly lower than our margins for retail gas sales. The price increases and increased transport volumes were offset, in part, by a decrease in residential therm deliveries. Residential therm deliveries decreased 2.3% as compared to 2004, due to slightly warmer weather and a decrease in use per customer that was driven in part by higher commodity prices. As measured by heating degree days, 2005 was less than 1% warmer than 2004.

Other Operation and Maintenance Expenses

2006 vs. 2005: Our other operation and maintenance expenses 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 vender 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. For further information on seams elimination charges, see Electric Transmission in Factors Affecting Results, Liquidity and Capital Resources below.

Our utility operation and maintenance expenses are expected to increase in 2007 as a result of increased amortizations related to the impact of the 2006 pricing increases. In addition, operation and maintenance expenses are influenced by wage inflation, employee benefit costs and the length of plant outages.

2005 vs. 2004: Other operation and maintenance expenses increased by $47.4 million or 4.9% during 2005 compared with 2004. The most significant changes in our operation and maintenance expense related to increased lease costs and increased nuclear outage costs. Partially offsetting these increases was a charge in 2004 for severance costs related to the voluntary severance program and lower employee costs in 2005 due to fewer employees.

The largest operations and maintenance increase for the utility energy segment related to $50.0 million of costs that we recognized under lease agreements between We Power and Wisconsin Electric in connection with our PTF strategy.

In addition to the increased lease costs, our nuclear operating and maintenance expense increased approximately $11.0 million due to two scheduled refueling outages in 2005 where we also replaced the reactor vessel heads. In 2004, we had one scheduled refueling outage. This increase was partially offset by a $10.0 million settlement we received to resolve a vendor dispute.

Additionally, in 2004 we recognized $28.2 million of severance related costs due to the voluntary severance program that was implemented in the second half of 2004. In 2005, we had approximately 210 fewer employees, which reduced operation and maintenance costs by $12.9 million.

Table of Contents

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont d)

Benefit costs increased $7.0 million between the comparative periods due to increased pension and medical costs. 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.

Depreciation, Decommissioning and Amortization Expense

2006 vs. 2005: Depreciation, decommissioning and amortization expenses 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 expenses. We estimate that the new rates reduced annual depreciation expense by approximately $17 million, which was offset, in part, by net plant additions in 2006. We expect Depreciation, decommissioning and amortization expenses in 2007 to increase as a result of an overall increase in utility plant assets in service.

2005 vs. 2004: Depreciation, decommissioning and amortization expense increased by $8.6 million in 2005 as compared to 2004. This increase was primarily due to increased depreciable plant balances.

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 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 2006, 2005 and 2004.

Non-Utility Energy Segment	2006	2005	2004
	(Millions of Dollars)		
Operating Revenues	$ 69.1	$ 40.0	$ 19.9
Other Operating Expenses			
Other Operation and Maintenance	14.4	14.4	12.9
Depreciation, Decommissioning and Amortization	11.2	5.9	1.4
Property and Revenue Taxes	0.4	0.2	1.0
Operating Income	$ 43.1	$ 19.5	$ 4.6

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

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. There were no earnings associated with this unit in the first six months of 2005.

Our non-utility energy segment is expected to generate operating income in 2007 that is comparable to 2006 as both years will include 12 months of operations of PWGS 1.

2005 vs. 2004: Our non-utility energy segment had operating income of $19.5 million during 2005 compared with $4.6 million during 2004. The increase in operating income between the comparative periods is primarily due to PWGS 1 commencing service in

July 2005. This unit had operating income of $18.9 million during its six months of operation in 2005.

Table of Contents

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont d)

CORPORATE AND OTHER CONTRIBUTION TO OPERATING INCOME

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 is attributable to lower operating earnings at Wispark. In the foreseeable future, we expect to have slight operating losses as we have minimal business operations in this segment.

2005 vs. 2004: Corporate and other affiliates had operating income of $1.0 million in 2005 compared with an operating loss of $3.2 million in 2004. The improved results reflect increased earnings from Wispark.

CONSOLIDATED OTHER INCOME AND DEDUCTIONS, NET

The following table identifies the components of consolidated other income and deductions, net during 2006, 2005 and 2004.

Other Income and Deductions, Net	2006	2005	2004
	(Millions of Dollars)		
Capitalized Carrying Costs	$ 25.0	$ 20.4	$ 12.7
AFUDC - Equity	14.6	9.2	2.8
Gross Receipts Tax Recovery	4.0	2.6	1.5
Gain on Sale of Guardian Investment	2.8		
Debt Redemption Costs			(22.9)
Other, net	6.7	(3.5)	(8.4)
Total Other Income and Deductions, Net	$ 53.1	$ 28.7	($ 14.3)

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. In 2007, we expect a reduction in AFUDC - Equity as we placed in service the new scrubber at our Pleasant Prairie Power Plant in the fourth quarter of 2006. The scrubber was installed as part of our EPA consent decree spending. For further information on the consent decree with the EPA, see Note S Commitments and Contingencies in the Notes to Consolidated Financial Statements.

2005 vs. 2004: Other income and deductions, net increased by $43.0 million in 2005 compared to 2004. In 2004, we recognized $22.9 million of debt redemption costs associated with the early redemption of approximately $500 million of long-term debt. Similar debt redemption costs were not incurred in 2005. We recognized higher capitalized carrying costs of $7.7 million. The AFUDC - Equity increased $6.4 million in 2005 due to a higher average balance of AFUDC qualifying utility construction projects in 2005.

CONSOLIDATED INTEREST EXPENSE

Interest Expense	2006	2005	2004
	(Millions of Dollars)		
Gross Interest Costs	$ 212.6	$ 202.1	$ 215.5
Less: Capitalized Interest	39.9	28.7	22.1

Interest Expense	$ 172.7	$ 173.4	$ 193.4

Table of Contents

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont d)

2006 vs. 2005: Interest expense 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.

We expect total interest expense in 2007 to increase due to increased debt levels to fund our planned construction activity; however, these increases are mitigated by increases in our capitalized interest. To the extent that we incur debt associated with CWIP, we capitalize the interest costs in accordance with our accounting policies.

2005 vs. 2004: Total interest expense decreased by $20.0 million in 2005 compared with 2004. The decrease in interest expense primarily reflects lower average debt levels in 2005 as compared to 2004. During 2004, we reduced debt levels by $654.2 million primarily with proceeds from the sale of our manufacturing segment. However, due to the increased construction activity our 2005 year end debt balances increased by $291.9 million.

CONSOLIDATED INCOME TAXES

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. We expect our 2007 annual effective tax rate to range between 38% and 39%.

2005 vs. 2004: Our effective tax rate applicable to continuing operations was 33.0% in 2005 compared to 37.7% in 2004. In 2005, we reversed $16.3 million of valuation allowances 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 this item, our effective tax rate was 36.6%. For further information see Note H Income Taxes in the Notes to Consolidated Financial Statements.

DISCONTINUED OPERATIONS

Our discontinued operations include our Minergy Neenah facility which was sold in September 2006, our Calumet facility which was sold in May 2005 and our manufacturing operations which were sold in July 2004.

The following table identifies the primary components of net income from discontinued operations during 2006, 2005 and 2004.

Discontinued Operations	2006	2005	2004
	(Millions of Dollars)		
Manufacturing	$ 2.4	$	$ 184.2
Non-Utility and Other	1.5	5.1	(97.4)
Income from Discontinued Operations, Net of Tax	$ 3.9	$ 5.1	$ 86.8

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.

Table of Contents

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont d)

Our 2004 earnings from discontinued operations reflect an after-tax gain of $152.3 million on the sale of our manufacturing business. Our 2004 earnings from discontinued operations also reflect impairment charges of $79.3 million after-tax related to Calumet and $17.6 million after-tax related to 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 2006, 2005 and 2004:

Wisconsin Energy Corporation	2006	2005	2004
		(Millions of Dollars)	
Cash Provided by (Used in)			
Operating Activities	$ 729.8	$ 576.9	$ 599.0
Investing Activities	($ 939.3)	($ 697.1)	$ 242.8
Financing Activities	$ 173.3	$ 157.8	($ 834.3)

Operating Activities

Cash provided by operating activities for 2006 totaled $729.8 million, which is a $152.9 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.

Cash provided by operating activities decreased to $576.9 million during 2005 compared with $599.0 million during 2004. This decline reflected increased working capital needs for our utility business and an increase in deferred costs, offset in part by lower cash taxes and increased cash earnings. During 2005, we experienced significant increases in natural gas costs which increased our working capital requirements for natural gas in storage. The increased natural gas costs also led to an increase in accounts receivable as the cost of gas is recovered dollar for dollar in our natural gas revenues. During 2005, we also experienced increased deferred costs related to transmission costs and deferred fuel. During 2005, our cash taxes were lower than 2004 due to the ability to realize tax benefits on the sale of non-utility assets and accelerated tax depreciation on PWGS 1.

Investing Activities

During 2006, net cash outflows from investing activities were $939.3 million compared with net cash outflows of $697.1 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.

During 2005, we had $697.1 million of net cash outflows from investing activities. In 2004, we had net cash inflows from investing activities of $242.8 million. In 2005, capital expenditures increased related to our PTF strategy at We Power and for compliance with the consent decree

entered into with the EPA. See Factors Affecting Results, Liquidity and Capital Resources Environmental Matters. In addition, expenditures associated with nuclear fuel purchases were higher during 2005. In 2004, we recognized proceeds of $857.0 million from the sale of our manufacturing segment.

Table of Contents

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont d)

The following table identifies capital expenditures by year:

Capital Expenditures	2006	2005	2004
	(Millions of Dollars)		
Utility Energy	$ 459.9	$ 458.6	$ 426.5
We Power	466.1	276.4	190.4
Other	2.7	10.1	19.6
Total Capital Expenditures	$ 928.7	$ 745.1	$ 636.5

In connection with our growth strategy, which was announced in 2000, we have been focusing on divesting non-core assets and investing in core regulated assets. The sale of assets is a significant component of our investing activities. From 2000 through 2006, we have received approximately $2.2 billion of cash proceeds from the divestiture of assets. In 2007, if we are able to close on the sale of Point Beach, we expect to receive an additional $1 billion of after-tax cash proceeds. However, except for the potential sale of Point Beach, we do not expect to have a significant level of asset sales in the future.

The following table identifies cash proceeds from asset sales.

Asset Sales	2006	2005	2004
	(Millions of Dollars)		
Guardian	$ 38.5	$	$
Real Estate	20.1	54.5	38.7
Wisvest		37.1	
We Power		34.6	
Manufacturing			857.0
Other	43.8	7.6	3.9
Total Asset Sales	$ 102.4	$ 133.8	$ 899.6

Financing Activities

The following table summarizes our cash flows from financing activities:

	2006	2005	2004
	(Millions of Dollars)		
Increase (Reduction) Debt	$ 299.7	$ 291.9	($ 654.2)
Dividends on Common Stock	(107.6)	(102.9)	(97.8)
Common Stock, net	(21.2)	(28.1)	(81.8)
Other	2.4	(3.1)	(0.5)
Cash Provided by (Used in) Financing	$ 173.3	$ 157.8	($ 834.3)

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 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.

Table of Contents

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont d)

In July 2005, PWGS issued $155.0 million of 4.91% senior notes in a private placement. The senior notes have a mortgage style repayment feature and have an average life approximating 15 years. The final payment is due July 15, 2030. Proceeds from the sale of the senior notes were used primarily to repay short-term debt incurred during construction at PWGS. For further information, see Note K Long-Term Debt in the Notes to Consolidated Financial Statements.

Wisconsin Gas retired at the scheduled maturity date $65 million of 6-3/8% Notes due November 1, 2005. In November 2005, Wisconsin Gas issued $90 million of 5.90% Debentures due December 1, 2035. The proceeds from the sale were used to repay a portion of our outstanding commercial paper. The commercial paper was incurred to both retire the $65 million of 6-3/8% Notes and for working capital requirements.

During 2004, the proceeds from asset sales as well as improved cash flows from operations allowed us to retire $654.2 million of debt, including $200 million of 6.85% Trust Preferred Securities and $300 million of 5.875% senior notes due April 1, 2006.

No new shares of Wisconsin Energy s common stock were issued in 2006 and 2005. During January and February 2004, we issued approximately 0.2 million new shares of common stock in connection with our dividend reinvestment plan and various employee benefit plans and we received payments aggregating $4.8 million. In February 2004, we announced that we did not expect to issue new shares under these programs; rather we instructed the independent plan agents to begin purchasing the shares in the open market in lieu of issuing new shares. During 2006, 2005 and 2004, our plan agents purchased 1.1 million shares at a cost of $48.0 million, 2.0 million shares at a cost of $75.1 million and 3.2 million shares at a cost of $102.3 million, respectively, to fulfill exercised stock options and restricted stock awards. In 2006, 2005, and 2004 we received proceeds of $26.8 million, $47.0 million and $66.1 million related to the exercise of stock options. Prior to February 2004, we issued new shares to fulfill these obligations.

In September 2000, the Board of Directors amended the common stock repurchase program to authorize us to purchase up to $400 million of our shares of common stock in the open market. This program expired in December 2004. In March 2004, we announced that under this plan we would resume purchasing approximately $50 million of our common shares in the open market with the proceeds from the sale of the manufacturing business, which was effective July 31, 2004. During 2004, we purchased approximately 1.6 million shares of common stock for $50.4 million under this plan. We ceased repurchasing shares in October 2004. Over the life of the plan we repurchased and retired 14.9 million shares at a cost of $344.0 million.

CAPITAL RESOURCES AND REQUIREMENTS

In December 2006, we announced that Wisconsin Electric had reached an agreement to sell Point Beach to an affiliate of FPL. If the sale is completed, we expect to receive over $1 billion of after-tax proceeds from the sale and liquidation of decommissioning trust assets. In the short-term, these proceeds would be used to reduce outstanding debt or temporarily invested in short term securities. However, as discussed in Corporate Developments - Corporate Strategy, we have filed an application with the PSCW that outlines our intention to use the gain (net of transaction related costs) on the proceeds for the benefit of our customers as decided by our regulators in future rate proceedings. As such, if the Point Beach sale is approved, we believe that the cash proceeds, after transaction costs and return of invested capital, that will result from the sale will replace revenues that we would have received in future rate proceedings.

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 59.5% at December 31, 2006 due primarily to asset sales. Over the next several years, we expect to have some limited asset sales, but at levels significantly lower than the previous seven year level.

Capital Resources

We anticipate meeting our capital requirements during 2007 and the next several years primarily through internally generated funds and short-term borrowings, supplemented by the issuance of intermediate or long-term debt or other

Table of Contents

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont d)

capital market (other than common stock) securities depending on market conditions and other factors. During 2007, Wisconsin Energy may issue up to $600 million of debt or debt-like securities depending on market conditions and other factors.

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 and internally generated cash.

In March 2004, the Governor of Wisconsin signed into law a measure that gives utilities the ability to securitize the portion of customer bills that recovers the cost of certain investments intended to improve the environment. We evaluated the possible issuance of environmental trust bonds for some time. However, after extensive evaluation and analysis, we will not be pursuing an issuance of environmental trust bonds.

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, 2006, we had approximately $1.7 billion of available unused lines under our bank back-up credit facilities on a consolidated basis and approximately $911.9 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, 2006.

Company	Total Facility	Letters of Credit	Credit Available (Millions of Dollars)	Facility Expiration	Facility Term
Wisconsin Energy	$900.0	$ 1.5	$898.5	April 2011	5 year
Wisconsin Electric	$500.0	$14.1	$485.9	March 2011	5 year
Wisconsin Gas	$300.0	$	$300.0	March 2011	5 year

On March 30, 2006, Wisconsin Electric entered into an unsecured five year $500 million bank back-up credit facility to replace a $250 million three year credit facility with an expiration date of June 2007 and a $125 million three year credit facility with an expiration date of November 2007. This new facility will expire in March 2011.

On March 30, 2006, Wisconsin Gas entered into an unsecured five year $300 million bank back-up credit facility to replace a $200 million three year credit facility with an expiration date of June 2007. This new facility will expire in March 2011.

On April 6, 2006, Wisconsin Energy entered into an unsecured five year $900 million bank back-up credit facility to replace a $300 million credit facility that would have expired on April 8, 2006 and a $300 million credit facility with an expiration date of June 2007. This new credit facility will expire in April 2011.

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

Table of Contents

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont d)

The following table shows our consolidated capitalization structure at December 31:

Capitalization Structure	2006		2005	
	(Millions of Dollars)			
Common Equity	$ 2,889.0	40.1%	$ 2,680.1	40.0%
Preferred Stock of Subsidiary	30.4	0.4%	30.4	0.5%
Long-Term Debt (including current maturities)	3,370.1	46.8%	3,527.0	52.7%
Short-Term Debt	911.9	12.7%	456.3	6.8%
Total	$ 7,201.4	100.0%	$ 6,693.8	100.0%
Ratio of Debt to Total Capital		59.5%		59.5%

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, 2006.

	S&P	Moody s	Fitch
Wisconsin Energy			
Commercial Paper	A-2	P-2	F2
Unsecured Senior Debt	BBB+	A3	A-
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-

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.

On June 8, 2006, S&P affirmed the security ratings and ratings outlook of Wisconsin Energy, Wisconsin Electric and Wisconsin Gas. The security ratings outlooks assigned by S&P for Wisconsin Energy, Wisconsin Electric, Wisconsin Gas and Wisconsin Energy Capital Corporation are negative.

The security rating outlooks assigned by Moody s for Wisconsin Energy, Wisconsin Electric, Wisconsin Gas and Wisconsin Energy Capital Corporation are all stable. In February 2004, Moody s changed the rating outlook for Wisconsin Energy and Wisconsin Energy Capital Corporation from negative to stable.

Table of Contents

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont d)

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 current estimated 2007, 2008 and 2009 capital expenditures, excluding the purchase of nuclear fuel, are as follows:

Capital Expenditures	Actual 2006	Estimated 2007	Estimated 2008	Estimated 2009
		(Millions of Dollars)		
Utility Energy	$ 459.9	$ 661.0	$ 551.0	$ 587.0
We Power	466.1	701.0	475.0	216.0
Other	2.7	9.0	4.0	5.0
Total	$ 928.7	$ 1,371.0	$ 1,030.0	$ 808.0

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, 2006, we have expended approximately $1.2 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 the PTF units will be completed by 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 two wind farm projects from Navitas Energy Inc. We plan to develop the wind sites and construct wind turbines with a combined generating capability between 130 and 200 MW. We estimate that the capital cost of the project, excluding AFUDC, will be up to $360 million. We anticipate the cost to build the wind farm projects would be recovered in Wisconsin Electric s rates. We expect the turbines to be placed in service in 2008 dependent upon the availability of wind turbines and the receipt of necessary regulatory approvals. For additional information on Wind Generation see Utility Rates and Regulatory Matters - Wind Generation below.

Investments in Outside Trusts: We have funded our pension obligations, certain other post-retirement obligations and future nuclear obligations in outside trusts. Collectively, these trusts had investments that exceeded $2.1 billion as of December 31, 2006. These trusts hold investments that are subject to the volatility of the stock market and interest rates. For further information see Note I Nuclear Operations and 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,

Table of Contents

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont d)

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, 2006:

		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)	$ 6,125.6	$ 442.4	$ 708.9	$ 735.3	$ 4,239.0
Capital Lease Obligations (c)	547.9	61.7	108.5	82.5	295.2
Operating Lease Obligations (d)	183.9	51.6	58.2	41.2	32.9
Purchase Obligations (e)	3,293.6	1,099.4	1,458.8	300.1	435.3
Other Long-Term Liabilities (f)	84.4	82.2	1.4	0.8	
Total Contractual Obligations	$ 10,235.4	$ 1,737.3	$ 2,335.8	$ 1,159.9	$ 5,002.4

(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. The table excludes the long-term power purchase commitment which is contingent upon the sale of Point Beach.
(b) Principal and interest payments on our Long-Term Debt and the Long-Term Debt of our affiliates (excluding capital lease obligations).
(c) Capital Lease Obligations of Wisconsin Electric for nuclear fuel lease and purchase power commitments.
(d) Operating Lease Obligations for purchase power 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.
(f) Other Long-Term Liabilities includes the expected 2007 supplemental executive retirement plan obligation and the 2007 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.

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 2007, 2008 and 2009 estimated capital expenditures, see Capital Requirements above.

Table of Contents

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont d)

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 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 to permits obtained, 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, 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.

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

Table of Contents

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont d)

short- and long-term procurement contracts with various suppliers for the purchase of coal, uranium, natural gas and fuel oil. In addition, we manage the risk of price volatility by utilizing gas 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 2007, 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 2006 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 significantly 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 is added to the nation s energy supply mix.

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. In 2004 and 2003, we had approval from the PSCW to defer residential bad debt net write-offs that exceed amounts allowed in rates.

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 2006, 2005 and 2004, 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, 2006. 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, 2006 of our outstanding portfolio of $911.9 million of short-term debt with a weighted average interest rate of 5.37% and $179.0 million of variable-rate long-term debt with a weighted average interest rate of 3.97%. A one-percentage point change in interest rates would cause our annual interest expense to increase or decrease by approximately $9.1 million before taxes from short-term borrowings and $1.8 million before taxes from variable rate long-term debt outstanding.

Marketable Securities Return: We fund our pension, OPEB and nuclear decommissioning 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, other post-retirement benefit and nuclear decommissioning expenses. Additionally, future contributions can also be affected by changes in the market price of trust fund assets. We expect that the risk of

Table of Contents

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont d)

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, 2006, 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	$1,057.7
Nuclear decommissioning trust funds	$ 881.6
Other post-retirement benefits trust funds	$ 203.7

Fiduciary oversight of the pension and other post-retirement plan 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%.

Fiduciary oversight for the nuclear decommissioning trust fund investments is also the responsibility of the Investment Trust Policy Committee. Qualified external investment managers are also engaged to manage these investments. Asset/liability studies are periodically conducted with the assistance of an outside investment advisor, subject to additional constraints established by the PSCW. The current study projects long-term, annualized returns of approximately 9%. Current PSCW constraints allow a maximum allocation of 65% in equities.

Wisconsin Electric insures various property and outage risks through NEIL. Annually, NEIL reviews its underwriting and investment results and determines the feasibility of granting a distribution to policyholders. Adverse loss experience, rising reinsurance costs or impaired investment results at NEIL could result in increased costs or decreased distributions to Wisconsin Electric.

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 and energy services contracts and employee benefit plans that could require, in the event of a credit rating change to below investment grade, a termination payment if collateral is not provided or an accelerated payment. At December 31, 2006, we estimate that the potential payments under these agreements that could result from credit rating downgrades totaled approximately $71.2 million.

Economic Conditions: We are exposed to market risks in the regional midwest economy for our utility energy segment.

Inflation: We continue to monitor the impact of inflation, especially with respect to the rising costs of medical plans, in order to minimize its effects in future years through pricing strategies, productivity improvements and cost reductions. Except for continuance of an increasing trend in the inflation of medical costs and the impacts on our medical and post-retirement benefit plans, we have expectations of low-to-moderate inflation. We do not believe the impact of general inflation will have a material effect 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 above.

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

Table of Contents

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont d)

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	Summer 2008	$ 329 million
OC 1	Summer 2009	$ 1,300 million
OC 2	Summer 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 our primary regulator. 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 time for the peak summer season in 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

Table of Contents

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont d)

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.

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. Certain of these permits continue to be contested, but remain in effect unless and until overturned by a reviewing court or administrative law judge. The major permits are discussed below.

The WDNR issued a Chapter 30 permit for wetlands and waterways alterations and construction on the bed of Lake Michigan for the construction of the Oak Creek expansion. The permit has been the subject of appeals since 2003. The final appeal was resolved by the Wisconsin Court of Appeals in February 2006, and the period for appeal of that decision to the Wisconsin Supreme Court has expired.

We applied to the WDNR to modify the existing WPDES permit that is required for operation of the water intake and discharge system for the planned Oak Creek expansion and existing Oak Creek generating units. In March 2005, the WDNR determined that the proposed cooling water intake structure and water discharge system meets regulatory requirements and reissued the WPDES permit with specific limitations and conditions. The opponents filed a petition for judicial review in Dane County Circuit Court and a request for a contested case proceeding with the WDNR. In September 2005, the judicial review petition was dismissed by agreement of the parties. The WDNR granted a contested case hearing that was held in March 2006. The administrative law judge upheld the issuance of the permit in a decision issued in July 2006. In August 2006, the opponents filed for judicial review of the administrative law judge s decision upholding the issuance of the permit. Briefing was completed in December 2006. However, based on the federal court decision discussed below, the opponents filed a motion on January 26, 2007 requesting supplemental briefing. In a telephone conference on February 2, 2007, the Court said that additional briefing was not necessary, but that it might request oral argument before issuing its decision regarding review of the permit. We anticipate a decision in the case in 2007.

Table of Contents

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont d)

On January 26, 2007, the Federal Court of Appeals for the Second Circuit, issued a decision in Riverkeeper, Inc. v. EPA, Nos. 04-6692-ag(L) et al. (2d Cir. 2007) relating to the 316(b) rules for cooling water intake systems for existing large utility plants. The Second Circuit Court found certain portions of the rule impermissible and remanded several parts of the rule to the EPA for further consideration or potential additional rulemaking. The WPDES permit for our Oak Creek expansion and existing Oak Creek generating units is a state permit, issued by WDNR with concurrence of EPA. Based on our review of the Second Circuit decision, we do not believe the decision invalidates the WPDES permit for Oak Creek. However, we cannot predict what, if any, impact the decision may have on the court s decision in the Dane County Circuit Court case.

In May 2005, we received the Army Corps of Engineers federal permit necessary for the construction of the Oak Creek expansion. Opponents may appeal the permit in federal court.

In addition, 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, 7% are regulated by the MPSC and the balance of our electric revenues are regulated by FERC. All of our natural gas 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/.

Overview: For the period from March 2000 until December 31, 2005, the rates of Wisconsin Electric and Wisconsin Gas were governed by an order from the PSCW in connection with the approval of the WICOR acquisition. Under this order, Wisconsin Electric and Wisconsin Gas were restricted from increasing Wisconsin rates for a five year period ending December 31, 2005, with certain limited exceptions.

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

Table of Contents

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont d)

Service - Wisconsin Electric	Incremental Annualized Revenue Increase (Millions)	Percent Change in Rates (%)	Effective Date
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 (a)	$ 7.8	31.5%	January 26, 2006
Fuel electric, Michigan	$ 2.7	5.9%	January 1, 2006
Fuel electric, Wisconsin (b)	$ 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 (b)	$ 114.9	5.9%	March 18, 2005
Fuel electric, Michigan	$ 3.4	8.0%	January 1, 2005
Fuel electric, Michigan	$ 1.3	3.1%	October 1, 2004
Retail steam, Wisconsin	$ 0.5	3.4%	May 5, 2004
Retail electric, Wisconsin (c)	$ 59.0	3.3%	May 5, 2004
Fuel electric, Michigan	$ 3.3	7.6%	January 1, 2004

(a) In January 2006, the PSCW issued a final order authorizing an increase in steam rates of $7.8 million over the two year period of 2006 and 2007.

(b) In November 2005, the PSCW issued a final order authorizing a fuel surcharge for $7.7 million of additional fuel costs. In March 2005, the PSCW issued an interim order authorizing a fuel surcharge for $114.9 million that was effective until the November 2005 final order was issued by the PSCW. The final November 2005 order for $122.6 million superseded the March 2005 interim order.

(c) In May 2004, the PSCW issued a final order authorizing an increase in electric rates for costs associated with the PWGS under construction and increased costs associated with low-income energy assistance.

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 does 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.

For 2007, Wisconsin Electric expects to 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%.

Table of Contents

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont d)

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%.

2004 Wisconsin Gas Pricing: In March 2004, the PSCW approved an annual rate increase of $25.9 million related to increased costs associated with the construction of the Ixonia lateral and for increased costs associated with low-income energy assistance.

2008 Pricing: We anticipate filing rate cases for Wisconsin Electric and Wisconsin Gas in May 2007 for new rates effective in January 2008.

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. We anticipate a decision from the Wisconsin Court of Appeals in 2007.

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 reconstruction 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 of 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 the ATC, our transmission costs have escalated due to the socialization of costs within the 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 the deferral of transmission costs in excess of amounts imbedded in rates. We are allowed to earn a return on the unrecovered transmission costs at our weighted average cost of capital. As of December 31, 2006, we have deferred $192.2 million of unrecovered transmission costs. In January 2006, our rates were increased by approximately $67.5 million annually to recover transmission costs that were not currently in rates. We will continue to accrue carrying costs on the unrecovered balances.

Table of Contents

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont d)

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. Imbedded 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 imbedded 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 2006, the upper band was 2%. As discussed above, 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 short-term rates. Approximately $28.7 million, including interest, in refunds were issued as a credit on customer bills in October 2006. We had favorable fuel recoveries of approximately $37.4 million, excluding interest, for 2006. We received approval from the PSCW to refund an additional $10 million, including interest, during the first quarter of 2007. In September 2006, the PSCW determined that if the total favorable recoveries for 2006 exceeded $36 million, interest on the favorable recoveries in excess of $36 million will 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. For 2007, 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 width 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 2006 and 2005, no additional revenues were earned under the incentive portion of the GCRM and $0.2 million of additional revenues were earned in 2004 under the GCRM.

Bad Debt Costs: In 2004, due to a combination of unusually high natural gas prices, a soft economy within our utility service territories, and limited governmental assistance available to low-income customers, we saw a significant increase in residential uncollectible accounts receivable. These factors led us to request and receive letters from the PSCW which allowed us to defer the costs of residential bad debts to the extent that the costs exceeded the amounts allowed in rates. As a result of these letters from the PSCW, we deferred approximately $21.2 million in 2004 related to bad debt costs.

In January 2006, the PSCW issued an order approving the amortization over the next five years of the 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 December 2004, we filed with the PSCW a request to implement a pilot program, which, among other things, is designed to better match our collection efforts with the ability of low income customers to pay their bills. Included in this filing was a request to implement escrow accounting for all residential bad debt costs. In February 2005, the PSCW approved our pilot program and our request for the use of escrow accounting. 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 exceed amounts allowed in rates. As a result of this approval from the PSCW, we escrowed approximately $3.7 million in 2006 and $17.2 million in 2005 related to bad debt costs. These amounts were not addressed in the January 2006 rate order, and will therefore be considered for recovery in future rates, subject to audit and approval of the PSCW. We will continue following the escrow method of accounting for bad debts as approved in the March 2005 PSCW order.

MISO Midwest Market: 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 Midwest

Table of Contents

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont d)

Market. 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 Midwest Market 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. For additional information see Industry Restructuring and Competition Electric Transmission and Energy Markets MISO.

Wholesale Electric Rates: On August 1, 2006, Wisconsin Electric filed a wholesale rate case with FERC. The filing requests an annual increase in rates of approximately $16.7 million applicable to four existing wholesale electric customers. In November 2006, FERC accepted the rate filing subject to refund with interest; however, the rates have not yet been approved. Three of the existing customer s rates are effective January 1, 2007 and the remaining $16.5 million for the largest wholesale customers rates will be effective May 1, 2007. The rates are subject to refund and hearing and settlement procedures.

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.

***Nuclear Refueling Outages - 2005*:** In May 2005, we requested and received approval from the PSCW to defer replacement power costs incurred after May 30, 2005 due to the longer-than-expected outage at Point Beach Unit 2. We deferred $22.1 million of incremental purchased power costs related to the extended outage.

Renewables, Efficiency and Conservation: In March 2006, Wisconsin enacted new public benefits legislation, Act 141. This legislation 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 are evaluating the requirements of Act 141. Additionally, the details of the new requirements are subject to administrative rulemaking that could take until March 2007 to complete.

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, the law requires that 1.2% of utilities operating revenues be set aside for these programs. We do not expect the impact of this action to be material as the 1.2% approximates the amounts currently in our rates for these matters. The effective date of this action is July 1, 2007. The PSCW is expected to develop implementation plans over the upcoming months.

Table of Contents

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont d)

Wind Generation: In June 2005, we purchased the development rights to two wind farm projects (Blue Sky Green Field) from Navitas Energy Inc. We plan to develop the wind sites and construct wind turbines with a combined generating capacity of between approximately 130 and 200 MW. We filed for approval of a CPCN with the PSCW in March 2006. A prehearing conference was held in September 2006. In addition, our direct testimony was filed in September 2006. Staff and intervenor testimony was filed in October 2006 and rebuttal testimony by all parties was filed in November 2006. Hearings were held at the end of November 2006. In February 2007, the PSCW issued a written notice approving the CPCN. In addition to the CPCN approval, we are working to secure any additional permits necessary to commence construction. In early 2006, the United States Congress directed the Department of Defense and the Department of Homeland Security to investigate possible conflicts between military radar and wind turbine installations. In November 2006, we received confirmation that Blue Sky Green Field poses no such conflict, and to date the FAA has issued all requested permits for Blue Sky Green Field.

We estimate that the capital cost of the project, excluding AFUDC, will be up to $360 million. The demand for wind turbine equipment has been strong, pushing off equipment deliveries to dates later than originally anticipated. We currently expect the turbines to be placed in service by the end of 2008, dependent upon the availability of wind turbines and the receipt of necessary regulatory approvals.

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 2006. 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; however, pursuant to MISO s orders, we did interrupt or curtail service to non-firm customers who participate in load management programs in exchange for discounted rates.

We expect to have adequate capacity to meet all of our firm load obligations during 2007. However, extremely hot weather, unexpected equipment failure or unavailability could require us to call upon load management procedures during 2007 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, (3) remediation of former manufactured gas plant sites, (4) disposal of used nuclear fuel and (5) the eventual decommissioning of Point Beach.

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) 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 WDNR and EPA to reduce emissions of SO_2 and NO_x by more than 65% and mercury by 50% by 2013 from our coal-fired power plants in Wisconsin and Michigan, (6) evaluating and implementing improvements to our cooling water intake systems, (7) recycling of ash from coal-fired generating units and (8) 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

Table of Contents

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont d)

principally associated with the installation of air quality controls on Pleasant Prairie Units 1 and 2 and Oak Creek Units 5-8. Through December 31, 2006, we have spent approximately $355.0 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. For further information concerning disposal of used nuclear fuel and nuclear power plant decommissioning, see Nuclear Operations below and Note I Nuclear Operations in the Notes to Consolidated Financial Statements in this report, respectively.

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 $PM_{2.5}$. The states are currently developing rules to implement the new standards. Although specific emission control requirements are not yet defined, we believe that the revised standards will likely require significant reductions in SO_2 and NO_x emissions from coal-fired generating facilities. We expect that reductions needed to achieve compliance with the 8-hour ozone attainment standard will be implemented in stages. Reductions associated with the fine particulate matter standards are expected to be implemented in stages after the year 2010 and extending to the year 2017. We are currently unable to predict the impact that the revised air quality standards might have on the operations of our existing coal-fired generating facilities until the states develop rules and submit State Implementation Plans (SIP) to the EPA to demonstrate how they intend to comply with the 8-hour ozone and fine particulate matter NAAQS.

8-hour Ozone Standard: In April 2004, the EPA designated 10 counties in Southeastern Wisconsin as nonattainment areas for the 8-hour ozone NAAQS. States are required to develop and submit SIPs to the EPA by June 2007 to demonstrate how they intend to comply with the 8-hour ozone NAAQS. We expect that reductions needed to achieve compliance with the 8-hour ozone attainment standard will be implemented in stages and that some or all of these reductions will be accomplished through implementation of the CAIR. See below for further information regarding CAIR. We believe that compliance with the NO_x emission reductions requirements under the agreements with the WDNR and EPA will substantially mitigate costs to comply with the EPA s 8-hour ozone NAAQS. However, the timing of the requirements may be impacted by requiring earlier installation of NO_x controls at some units, depending on how the states implement the rules.

$PM_{2.5}$ Standard: In December 2004, the EPA designated $PM_{2.5}$ non-attainment areas in the country. All counties in the State of 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.

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 are required to develop and submit implementation plans by no later than March 2007. In Wisconsin, a final CAIR rule has been approved by the WDNR and is proceeding through the administrative process. Although the impacts are uncertain until the states implementation plans are in place, we believe that compliance with the NO_x and SO_2 emission reductions requirements under the agreements with the WDNR and EPA 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 limits mercury emissions from new and existing coal-fired power plants, and caps utility mercury emission in two phases, applicable in 2010 and 2018. The caps limit emissions at approximately 20% and ultimately 70% below today s utility mercury levels. The states were required to develop and submit implementation plans by November 2006, but neither state has finalized its plan yet. Until those plans are in place, it is not possible to estimate the final impact of the CAMR, but additional expenditures are anticipated in order to meet both phases of the federal rule. Because the technology is under

Table of Contents

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont d)

development, it is difficult to estimate the cost. 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 the new rule.

The federal rule is being challenged by a number of states including Wisconsin and Michigan. Depending on the litigation, the timing for compliance may be affected.

The WDNR independently developed mercury emission control rules that affect electric utilities in Wisconsin and issued state-only mercury control rules in October 2004. The rules explicitly recognize an underlying state statutory restriction that state regulations cannot be more stringent than those included in any federal program. The rules state that the WDNR must adopt state rule changes within 18 months of publication of any federal rules. State rules are to be changed to be consistent with, and no more restrictive than, any federal rules. It is not possible to determine if there will be requirements in addition to CAMR until a rule is in place or the existing rule is set aside. Because the 18 month deadline has passed, we are reviewing our options.

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 then 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 must 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. We are currently unable to predict the impact that CAVR might have on the operations of our existing coal-fired generating facilities until the states develop rules and submit implementation plans to the EPA.

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. This 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 rule for Wisconsin Electric s Oak Creek Power Plant, We Power s Oak Creek expansion and PWGS have been included in project costs. Studies to determine what costs, if any, that may be associated with Wisconsin Electric s other existing facilities are expected to take place over the next two years.

On January 26, 2007, the Federal Court of Appeals for the Second Circuit issued a decision concerning the 316(b) rule for existing facilities (Riverkeeper, Inc. v. EPA, Nos. 04-6692-ag(L) (2d Cir. 2007)). The Second Circuit Court found certain portions of the rule impermissible and remanded several parts of the rule to the EPA for further consideration or potential additional rulemaking. Until such time as the EPA completes those actions, we cannot predict what impact the changes, if any, to the rule may have on our facilities.

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 Proposed Consent Decree: Wisconsin Electric entered into a proposed consent decree with the EPA to address all matters relating to information requests received from the EPA pursuant to Section 114(a) of the Clean Air Act. For further information, see Note S Commitments and Contingencies in the Notes to Consolidated Financial Statements.

Table of Contents

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont d)

Greenhouse Gases: There have been international efforts seeking legally binding reductions in emissions of greenhouse gases, principally CO_2, including the United Nations Framework Convention on Climate Change held in Kyoto, Japan. While the Bush Administration has not supported U.S. ratification of the Kyoto Protocol or other legislation requiring reductions in CO_2, in 2002, the Bush Administration announced a goal of reducing the greenhouse gas intensity of the U.S. economy by 18% by 2012. In addition, in December 2004, the DOE announced the Climate VISION program in furtherance of reduced greenhouse gas emissions. We continue to take voluntary measures to reduce our emissions of greenhouse gases. However, legislative proposals that would impose mandatory restrictions on CO_2 continue to be considered in Congress. The impact of any future legislation that would require reductions in greenhouse gases cannot be assessed at this time.

We continue to support flexible, market-based strategies to curb greenhouse gas emissions. These strategies include emissions trading, joint implementation projects and credit for early actions. We also 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 as part of the PTF strategy, including:

Repowering the Port Washington Power Plant from coal to natural gas combined cycle units.

Adding coal-fired units using state-of-the-art technology as part of the Oak Creek expansion.

Increasing investment in energy efficiency and conservation.

Maintaining and increasing non-emitting generation by potentially adding approximately 130 to 200 MW of wind capacity and increasing customer participation in the Energy for Tomorrow ® renewable energy program.

Successful renewal of the Point Beach units operating licenses.

LEGAL MATTERS

***Arbitration Proceedings*:** Our largest electric customers, two iron ore mines, operate in the Upper Peninsula of Michigan. The mines represent approximately 6% to 7% of our annual electric sales; however, the earnings are insignificant to us. The mines have special negotiated contracts that expire in December 2007. The contracts have price caps for approximately 80% of the energy sales. We do not recognize revenue on amounts billed that exceed 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 Midwest Market. The mines have notified us that they are disputing these billings and a portion of these disputed amounts have been deposited in escrow. In September 2005, the mines notified us that they filed for formal arbitration related to the contracts. We have notified the mines that we believe that they have failed to comply with certain notification provisions related to annual production as specified within the contracts. The arbitration hearings previously scheduled for October 2006 have been postponed and rescheduled for the third quarter of 2007 and we anticipate a decision in the fourth quarter of 2007. As of December 31, 2006, the mines have placed $29.3 million in escrow. As of December 31, 2005, the mines had placed $70.6 million in escrow. The decrease in the escrow balance relates to amounts that we refunded without interest for the amounts billed in 2005 that exceeded the price caps. At this time, we are unable to

predict the outcome of the formal arbitration process, but we believe that it will not have a material adverse impact on our financial condition or results of operations.

Although it is currently uncertain, we anticipate that we will provide power to the mines under the terms of one or more regulated tariffs to be approved by the MPSC beginning January 1, 2008.

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.

Table of Contents

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont d)

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. In 2003, the Wisconsin Supreme Court upheld a Court of Appeals affirmance of a jury verdict against Wisconsin Electric, awarding $1.2 million to the plaintiffs in a stray voltage lawsuit. The Supreme Court rejected the argument 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 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. Even though the claims which have been made against Wisconsin Electric with respect to stray voltage and ground currents are not expected to have a material adverse effect on its financial statements, we continue to evaluate various options and strategies to mitigate this risk.

NUCLEAR OPERATIONS

Point Beach Nuclear Plant: Wisconsin Electric owns two 518 MW electric generating units (Unit 1 and Unit 2) at Point Beach in Two Rivers, Wisconsin. Point Beach is operated by NMC, a joint venture of the Company and affiliates of other unaffiliated utilities. During 2006, 2005 and 2004, Point Beach provided approximately 25.3%, 20.0% and 23.7%, respectively, of Wisconsin Electric s net electric energy supply.

Each unit at Point Beach has a scheduled refueling outage approximately every 18 months. A refueling outage is scheduled for first quarter 2007. In the fourth quarter of 2006, Unit 2 had a scheduled refueling outage. In 2005, Unit 2 had a scheduled refueling outage over the second and third quarters, and Unit 1 had a scheduled refueling outage over the third and fourth quarters. During the 2005 scheduled refueling outages we replaced the reactor vessel heads at each unit. As expected, this work, along with other planned maintenance, resulted in longer than normal outages. During scheduled refueling outages, we incur significant operations and maintenance costs for work performed during the outages and we incur costs associated with replacement power. See Results of Operations for further discussion regarding the costs associated with nuclear outages. In 2004, Unit 1 had a scheduled refueling outage in the second quarter.

In December 2005, the NRC approved the request of NMC and Wisconsin Electric for license renewal. The new operating licenses expire in October 2030 for Unit 1 and March 2033 for Unit 2.

In February 2006, we announced that we were undertaking a formal review during 2006 regarding our options for the ownership and operation of Point Beach. At December 31, 2006, NMC operated six nuclear generating units. In addition, another owner has announced the planned sale of its unit. This sale would further reduce the size of the fleet operated by NMC. Given these changes, we believed it was prudent to evaluate a range of options for Point Beach. The options that we evaluated included: (1) continued operation by NMC, (2) continued operation by a third party operator other than NMC, (3) a return to in-house operation of the plant by Wisconsin Electric, (4) a sale of the Point Beach facility and (5) a partial sale of the plant with us retaining a minority interest in the Plant. Under this fifth option, the new majority owner would operate the plant. As part of our continuing review, we invited qualified third parties to tour Point Beach and review the data necessary to submit a bid to operate the plant or purchase all or part of the plant and operate it. We evaluated the bids received in comparison to continued operation of Point Beach by NMC or Wisconsin Electric. In December 2006, we announced that we had reached a definitive agreement to sell Point Beach to an affiliate of FPL. If and when the sale is completed (or earlier if an interim operating agreement with FPL is activated by us) NMC would transfer Point Beach s operating licenses to the buyer and we would withdraw from NMC and our relationship with NMC would be terminated. We would be required to pay a termination fee of approximately $12 million to withdraw from NMC and write-off our investment in NMC which is approximately $5 million at December 31, 2006. We also entered into a long-term power purchase agreement to purchase all of the existing capacity and energy of the plant, which will become effective upon the closing of the sale. Wisconsin Electric will have the unilateral option, subject to PSCW direction, to select a term for the power purchase agreement of either (i) an estimated 23 years for Unit 1 and 26 years for Unit 2, or (ii) 16 years for Unit 1 and 17 years for Unit 2. The sale of the plant and the long-term power purchase agreement are subject to review and approval by various regulatory agencies including the NRC, the PSCW, the MPSC and FERC. We have submitted a

Table of Contents

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont d)

request to the PSCW to defer any gain (net of transaction related costs) as a regulatory liability that would be applied to the benefit of our customers in future rate proceedings.

In July 2000, our senior management authorized the commencement of initial design work for the power uprate of both units at Point Beach. Subject to approval by the PSCW, the project could add approximately 90 MW of electrical output to Point Beach. In February 2003, Point Beach completed an equipment upgrade which resulted in a capacity increase of 7 MW per generating unit. If the proposed sale of Point Beach is completed, the uprate will be the responsibility of the new owner, FPL. In light of this, both companies are currently evaluating the timing for implementation of the power uprate project.

During 2002 and 2003, the NRC issued Final Significance Determination letters for two red (high safety significance) inspection findings regarding problems identified by Point Beach with the performance of the auxiliary feedwater system recirculation lines. During 2003, the NRC conducted a three-phase supplemental inspection of Point Beach in accordance with NRC Inspection Procedure 95003 to review corrective actions for the findings as well as the effectiveness of the corrective action, emergency preparedness and engineering programs.

The inspection results were presented at a public meeting in December 2003, and documented in a February 2004 NRC letter to NMC. The NRC determined that the plant is being operated in a manner that ensures public safety but also identified several performance issues in the areas of problem identification and resolution, emergency preparedness, electrical design basis calculation control and engineering-operations communication.

NMC responded to the supplemental inspection in February 2004 with specific commitments to address the NRC concerns, including revision of the Point Beach Excellence Plan. We were assessed a fine of $60,000 related to issues identified with our emergency preparedness. NRC reviewed the adequacy of the revised Excellence Plan and its implementation, and NMC received a confirmatory action letter in April 2004. Since then, the NRC has conducted numerous inspections and completed reviews of activities and meetings, noting the overall results were satisfactory. As a result, in the fourth quarter of 2006, the NRC closed the confirmatory action letter and concluded that the red findings received in 2002 and 2003 will no longer be considered in the NRC s assessment process. Point Beach will now receive routine baseline inspection by the NRC.

As a result of the September 11, 2001 terrorist attacks, the NRC and the industry have been strengthening security at nuclear power plants. Security at Point Beach remains at a high level, with limited access to the site continuing. Point Beach has responded to the NRC s February 2002 Order for interim safeguards and security compensatory measures. Point Beach has also responded to NRC orders regarding security of independent spent fuel storage installations, design basis threat and security officer training and work hours.

Used Nuclear Fuel Storage and Disposal: Wisconsin Electric is 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 has paid a total of $215.2 million into the Nuclear Waste Fund over the life 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 has subsequently scheduled a trial to determine damages for September 2007. Wisconsin Electric has incurred

substantial damages to date and damages continue to accrue. We are seeking

Table of Contents

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont d)

recovery of our damages in this lawsuit and we expect that any recoveries would be considered in setting future rates.

In July 2002, the President signed a resolution which allowed the DOE to begin preparation of the application to the NRC for a license to design and build a spent fuel repository in Yucca Mountain, Nevada. In July 2006, the DOE announced plans to submit a license application to the NRC for a nuclear waste repository at Yucca Mountain no later than June 30, 2008. The DOE also announced that if the requested legislative changes are enacted, the repository would be able to accept spent nuclear fuel starting in early 2017. It is not possible, at this time, to predict with certainty when the DOE will actually begin accepting used nuclear fuel.

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 Midwest Market, including the use of LMP to value electric transmission congestion and losses. The MISO Midwest Market 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: Electric utility revenues are regulated by the MPSC. In June 2000, the Governor of Michigan signed the Customer Choice and Electric Reliability Act into law empowering the MPSC to implement electric retail access in Michigan. The new law provides that

as of January 1, 2002, all Michigan retail customers of investor-owned utilities have the ability to choose their electric power producer.

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 the companies 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, reflecting the small market area, our competitive regulated power supply prices and a lack of interest in general in the Upper Peninsula of Michigan as a market for alternative electric suppliers.

Table of Contents

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont d)

Restructuring in Illinois: In 1999, the State of Illinois passed legislation that introduced retail electric choice for large customers and introduced choice for all retail customers in May 2002. This legislation has not had, and is not expected to have a material impact on Wisconsin Electric s business. Wisconsin Electric had one wholesale customer in Illinois, the City of Geneva, whose contract expired on December 31, 2005.

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 Midwest Market, which commenced operations on April 1, 2005. As part of this energy market, the 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 the use of FTRs. FTRs are allocated to market participants by MISO. A new allocation of FTRs was completed for the period of June 1, 2006 through May 31, 2007. 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. Due to certain changes in the units that MISO is dispatching, our unhedged congestion costs increased in 2006. These incremental congestion charges are deferred as approved by the PSCW, and we expect to recover these costs in future rates, subject to review and approval by the PSCW.

MISO deferred the costs to develop and start-up its energy market (new software systems and personnel). Now that the market is operational, the development and start-up costs are charged to MISO market participants, including Wisconsin Electric and Edison Sault.

To mitigate the risks of this new bid-based energy market, we requested deferral accounting treatment from the PSCW in January 2005 for certain incremental costs or benefits that may occur due to the implementation of the MISO Midwest Market. Our request excluded LMP energy costs because these costs are subject to recovery under the Wisconsin Fuel Cost Adjustment Procedure. In March 2005, the PSCW accepted our request. We submitted another joint proposal with other utilities in March 2005, requesting escrow accounting treatment for MISO Midwest Market 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 MISO, base transmission costs are currently being paid by LSE s located in the service territories of each MISO transmission owner. The current license plate transmission rate design is scheduled to be replaced on February 1, 2008. A filing delineating a new rate design, or substantiation for maintaining the existing rate design is due at FERC by August 1, 2007. At this time, we are not able to determine the impact of this rate design change on our transmission costs. FERC also ordered a seams elimination charge to be paid by MISO LSE s from December 1, 2004 until March 31, 2006, to compensate transmission owners for the loss of revenues resulting from the joining of a RTO and/or FERC s elimination of through and out transmission charges between the MISO and PJM. FERC ordered that certain existing transmission transactions continue to pay for through and out service from December 1, 2004 until March 31, 2006. The details of the seams elimination charge and the quantification of the existing transaction charge are the subject of a hearing process initiated by FERC in a February 2005 order. In January 2006, Wisconsin Electric along with certain other parties to the proceeding, submitted an offer of settlement to the presiding administrative law judge that resolved all issues set for hearing that impact Wisconsin Electric with regard to the continued payment of through and out transmission charges as well as the seams elimination charge. The administrative law judge certified the settlement to FERC, and FERC approved the settlement in April 2006.

In April 2006, FERC issued an order determining that MISO had not applied its energy markets tariff correctly in the assessment of Revenue Sufficiency Guarantee charges. FERC ordered MISO to resettle all affected transactions retroactive to April 1, 2005. In October 2006, we received a ruling from FERC. Since the ruling, FERC s order has been challenged by MISO and numerous other market participants. Any resettlement associated with the order is expected in 2007 and early 2008. Due to the complexity of the order, we are unable to precisely

determine the

Table of Contents

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont d)

overall financial implication to us. However, we do not believe that the result will have a material impact on our results of operations.

MISO is in the process of developing a market for two ancillary services, regulation reserves and contingency reserves. The MISO ancillary services market is currently proposed to begin in 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. We anticipate achieving a net reduction in fuel costs, but are unable to determine the amount of savings we will realize at this time. The MISO ancillary services market is expected to also enable MISO to assume significant balancing area responsibilities such as frequency control and disturbance control.

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.

Pension Reform: In August 2006, President Bush signed the Pension Protection Act of 2006. We are currently evaluating the Pension Protection Act of 2006, but we do not anticipate it will have a material impact on our results of operations or cash flows from operating activities.

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.

Table of Contents

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont d)

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 also may 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, 2006, we had $1,091.0 million in regulatory assets and $1,472.1 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 Other Post-retirement Benefits: 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.

Table of Contents

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont d)

Pension Plan Actuarial Assumption	Impact on Annual Cost (Millions of Dollars)
0.5% decrease in discount rate	$7.3
0.5% decrease in expected rate of return on plan assets	$4.8

In addition to pension plans, we maintain other post-retirement benefit 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 post-retirement benefit costs. Other post-retirement benefit 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 post-retirement benefit obligation and post-retirement costs. Our other post-retirement benefit 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 other post-retirement benefit 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	($2.8)
0.5% decrease in expected rate of return on plan assets	$0.9

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 2006 of $3,979.0 million included accrued utility revenues of $257.8 million as of December 31, 2006.

Asset Retirement Obligations: We account for legal liabilities for asset retirements at fair value in the period in which they are incurred according to the provisions of SFAS 143 and FIN 47. SFAS 143 applies primarily to decommissioning costs for Point Beach included in our utility energy segment. Using a discounted future cash flow methodology, our estimated nuclear asset retirement obligation was approximately $325.6 million at December 31, 2006. As it relates to our operations, FIN 47 applies primarily to asbestos removal costs. At December 31, 2006, we recorded an obligation of $39.6 million related to asbestos.

Calculation of the nuclear decommissioning asset retirement obligation is based upon projected decommissioning costs calculated by an independent decommissioning consulting firm, as well as several significant assumptions including the timing of future cash flows, future inflation rates and the discount rate applied to future cash flows. Assuming the following changes in key assumptions and holding all other assumptions constant, we estimate that our nuclear asset retirement obligation at December 31, 2006 would have changed by the following amounts:

Table of Contents

ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS - (Cont d)

Change in Assumption	Change in Liability (Millions of Dollars)
1% increase in inflation rate	$106.7
1% decrease in inflation rate	($79.8)

We were unable to identify a viable market for or third party who would be willing to assume this liability. Accordingly, we have used a market-risk premium of zero when measuring our nuclear asset retirement obligation. We estimate that for each 1% increment that would be included as a market-risk premium, our nuclear asset retirement obligation would increase by approximately $3.3 million.

For additional information concerning SFAS 143 and our estimated nuclear asset retirement obligation, see Note F Asset Retirement Obligations and Note I Nuclear Operations in the Notes to Consolidated Financial Statements.

Deferred Tax Assets Valuation Allowance: We record deferred tax asset valuation allowances in accordance with SFAS 109. As of December 31, 2006, we had approximately $3.4 million of valuation allowances that relate to state NOLs of various non-utility subsidiaries. These NOLs begin to expire in 2008 and it is not likely that we will be able to utilize them.

During 2006 and 2005, we reduced our valuation allowances by $5.8 million and $16.3 million respectively, as we were able to conclude that it was likely that we would be able to realize certain state NOLs recorded at certain of the non-utility subsidiaries in 2006 and at the Parent company in 2005. The 2005 conclusion was based on the favorable decision by the Supreme Court of Wisconsin in June 2005 that allowed the construction of the Oak Creek expansion as part of our PTF plan.

The PTF generating units will be owned by our subsidiaries organized as LLCs. Once the plants become operational, taxable income or loss of the LLCs will flow through to and be reported in the separate state income tax return of the Parent. As a result, the Parent no longer expects to generate large state taxable losses if all plants are in service. During 2005, the first of the four generating units was put into service. The determination of future state taxable income of the Parent is a significant estimate. Factors affecting the estimate include the amounts spent and timing for construction of the PTF generating units, the amount of debt and interest expense at the Parent and the consideration of available tax planning strategies.

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.

Table of Contents

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

WISCONSIN ENERGY CORPORATION

CONSOLIDATED INCOME STATEMENTS

Year Ended December 31

	2006	2005	2004
	(Millions of Dollars, Except Per Share Amounts)		
Operating Revenues	$ 3,996.4	$ 3,815.5	$ 3,406.1
Operating Expenses			
Fuel and purchased power	802.0	776.7	591.7
Cost of gas sold	1,018.3	1,047.3	890.9
Other operation and maintenance	1,183.7	1,007.9	986.7
Depreciation, decommissioning and amortization	326.4	332.0	319.5
Property and revenue taxes	97.5	88.7	87.3
Total Operating Expenses	3,427.9	3,252.6	2,876.1
Operating Income	568.5	562.9	530.0
Equity in Earnings of Transmission Affiliate	38.6	34.6	30.1
Other Income and Deductions, net	53.1	28.7	(14.3)
Interest Expense	172.7	173.4	193.4
Income from Continuing Operations Before Income Taxes	487.5	452.8	352.4
Income Taxes	175.0	149.2	132.8
Income from Continuing Operations	312.5	303.6	219.6
Income from Discontinued Operations, Net of Tax	3.9	5.1	86.8
Net Income	$ 316.4	$ 308.7	$ 306.4
Earnings Per Share (Basic)			
Continuing Operations	$ 2.67	$ 2.59	$ 1.87
Discontinued Operations	0.03	0.05	0.73
Total Earnings Per Share (Basic)	$ 2.70	$ 2.64	$ 2.60
Earnings Per Share (Diluted)			
Continuing Operations	$ 2.64	$ 2.56	$ 1.84
Discontinued Operations	0.03	0.05	0.73
Total Earnings Per Share (Diluted)	$ 2.67	$ 2.61	$ 2.57
Weighted Average Common Shares Outstanding (Millions)			
Basic	117.0	117.0	117.7
Diluted	118.4	118.4	119.1

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

Table of Contents

WISCONSIN ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

December 31

ASSETS

	2006	2005
	(Millions of Dollars)	
Property, Plant and Equipment		
In service	$ 9,265.4	$ 8,849.6
Accumulated depreciation	(3,423.7)	(3,288.5)
	5,841.7	5,561.1
Construction work in progress	992.4	596.6
Leased facilities, net	87.5	93.2
Nuclear fuel, net	130.9	112.0
Net Property, Plant and Equipment	7,052.5	6,362.9
Investments		
Nuclear decommissioning trust fund	881.6	782.1
Equity investment in transmission affiliate	228.5	205.8
Other	54.7	92.1
Total Investments	1,164.8	1,080.0
Current Assets		
Cash and cash equivalents	37.0	73.2
Accounts receivable, net of allowance for doubtful accounts of $35.1 and $36.6	379.3	441.8
Accrued revenues	257.8	262.9
Materials, supplies and inventories	417.2	451.6
Prepayments and other	136.7	147.5
Total Current Assets	1,228.0	1,377.0
Deferred Charges and Other Assets		
Regulatory assets	1,091.0	1,025.6
Goodwill, net	441.9	441.9
Other	152.0	174.6
Total Deferred Charges and Other Assets	1,684.9	1,642.1
Total Assets	$ 11,130.2	$ 10,462.0

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

Table of Contents

WISCONSIN ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

December 31

CAPITALIZATION AND LIABILITIES

	2006	2005
	(Millions of Dollars)	
Capitalization		
Common equity	$ 2,889.0	$ 2,680.1
Preferred stock of subsidiary	30.4	30.4
Long-term debt	3,073.4	3,031.0
Total Capitalization	5,992.8	5,741.5
Current Liabilities		
Long-term debt due currently	296.7	496.0
Short-term debt	911.9	456.3
Accounts payable	404.5	418.1
Payroll and vacation accrued	79.3	75.2
Accrued taxes	56.6	31.0
Accrued interest	25.3	28.2
Other	113.7	142.0
Total Current Liabilities	1,888.0	1,646.8
Deferred Credits and Other Liabilities		
Regulatory liabilities	1,472.1	1,373.2
Asset retirement obligations	371.7	355.5
Deferred income taxes - long-term	572.9	593.7
Accumulated deferred investment tax credits	52.0	56.3
Pension liability	195.9	274.4
Other long-term liabilities	584.8	420.6
Total Deferred Credits and Other Liabilities	3,249.4	3,073.7
Commitments and Contingencies (Note S)		
Total Capitalization and Liabilities	$ 11,130.2	$ 10,462.0

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

Table of Contents

WISCONSIN ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year Ended December 31

	2006	2005	2004
	(Millions of Dollars)		
Operating Activities			
Net income	$ 316.4	$ 308.7	$ 306.4
Reconciliation to cash			
Depreciation, decommissioning and amortization	336.8	350.0	352.6
Nuclear fuel expense amortization	28.7	23.0	24.0
Equity in earnings of transmission affiliate	(38.6)	(34.6)	(30.1)
Distributions from transmission affiliate	30.4	27.0	23.2
Deferred income taxes and investment tax credits, net	(54.0)	63.4	6.5
Deferred revenue	80.3	54.7	44.8
Change in - Accounts receivable and accrued revenues	61.2	(124.6)	(48.9)
Inventories	34.4	(48.5)	(20.4)
Other current assets	(26.5)	6.5	(20.0)
Accounts payable	(36.3)	93.4	37.6
Accrued income taxes, net	50.2	6.1	(8.5)
Deferred costs, net	(29.1)	(132.6)	(36.3)
Other current liabilities and other	(24.1)	(15.6)	(31.9)
Cash Provided by Operating Activities	729.8	576.9	599.0
Investing Activities			
Capital expenditures	(928.7)	(745.1)	(636.5)
Investment in transmission affiliate	(14.6)	(10.5)	(26.4)
Proceeds from asset sales, net	102.4	133.8	899.6
Nuclear fuel	(47.7)	(49.7)	(30.0)
Nuclear decommissioning funding	(17.6)	(17.6)	(17.6)
Proceeds from investments within nuclear decommissioning trust	530.7	435.7	327.2
Purchases of investments within nuclear decommissioning trust	(530.7)	(435.7)	(327.2)
Cash from discontinued operations			32.4
Other	(33.1)	(8.0)	21.3
Cash (Used in) Provided by Investing Activities	(939.3)	(697.1)	242.8
Financing Activities			
Exercise of stock options	26.8	47.0	70.9
Purchase of common stock	(48.0)	(75.1)	(152.7)
Dividends paid on common stock	(107.6)	(102.9)	(97.8)
Issuance of long-term debt	337.9	285.8	397.0
Retirement of long-term debt	(493.8)	(112.2)	(798.4)
Change in short-term debt	455.6	118.3	(252.8)
Other, net	2.4	(3.1)	(0.5)
Cash Provided by (Used in) Financing Activities	173.3	157.8	(834.3)
Change in Cash and Cash Equivalents	(36.2)	37.6	7.5

Cash and Cash Equivalents at Beginning of Year	73.2	35.6	28.1
Cash and Cash Equivalents at End of Year	$ 37.0	$ 73.2	$ 35.6
Discontinued Operations:			
Cash Provided by Operating Activities	$ 0.2	$ 2.1	$ 36.6
Cash Used in Investing Activities	(0.2)	(2.1)	(41.0)
Cash Used in Financing Activities			(2.0)
Change in Cash classified as held for sale	$	$	$ (6.4)
Supplemental Information - Cash Paid For			
Interest (net of amount capitalized)	$ 183.4	$ 162.3	$ 192.6
Income taxes (net of refunds)	$ 154.2	$ 47.5	$ 100.0

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

Table of Contents

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, 2003	$ 1.2	$ 841.8	$ 1,510.1	$ 3.1	$ (4.7)	$ 7.2	$ 2,358.7
Net income			306.4				306.4
Other comprehensive income							
Foreign currency translation				(8.6)			(8.6)
Minimum pension liability				(3.7)			(3.7)
Hedging, net				1.8			1.8
Comprehensive income			306.4	(10.5)			295.9
Common stock cash dividends of $0.83 per share			(97.8)				(97.8)
Common stock issued		70.9					70.9
Repurchase of common stock		(152.7)					(152.7)
Restricted stock and performance share awards		5.9			(6.5)		(0.6)
Amortization and forfeiture of performance shares and restricted stock		(0.9)			3.6		2.7
Stock options exercised		4.8				(4.8)	
Tax benefit from exercise of stock options		15.3					15.3
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)
Comprehensive income			308.7	(4.1)			304.6
Common stock cash dividends of $0.88 per share			(102.9)				(102.9)
Common stock issued		47.0					47.0
Repurchase 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)
Common stock issued		26.8					26.8
Repurchase of common stock		(48.0)					(48.0)
Tax benefit from exercise of stock options		8.4					8.4
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	$ 1.2	$ 755.5	$ 2,133.3	$ (1.6)	$	$ 0.6	$ 2,889.0

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

Table of Contents

WISCONSIN ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CAPITALIZATION

December 31

	2006	2005
	(Millions of Dollars)	
Common Equity (See Consolidated Statements of Common Equity)		
Common stock - $.01 par value; authorized 325,000,000 shares; outstanding - 116,969,063 and 116,980,775 shares	$ 1.2	$ 1.2
Other paid in capital	755.5	770.3
Retained earnings	2,133.3	1,924.5
Accumulated other comprehensive (loss)	(1.6)	(11.5)
Unearned compensation - restricted stock and performance share awards		(5.4)
Stock options exercisable	0.6	1.0
Total Common Equity	2,889.0	2,680.1
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)		
6-5/8% due 2006		200.0
9.47% due 2006		0.7
3.50% due 2007	250.0	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	
6-7/8% due 2095	100.0	100.0
Notes (secured, nonrecourse)		
6.36% effective rate due 2006		1.1
7.25% variable rate due 2006 (b)		9.3
2% stated rate due 2011	0.2	1.2
5.55% variable rate due 2028 (a)	14.6	15.1
4.81% effective rate due 2030	2.0	2.0
4.91% due 2007-2030	150.4	153.7

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

Table of Contents

WISCONSIN ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CAPITALIZATION - (Cont'd)

December 31

	2006	2005
	(Millions of Dollars)	
Long-Term Debt - (Cont'd)		
Notes (unsecured)		
3.55% variable rate due 2006 (b)	$	$ 1.0
5.875% due 2006		250.0
6.36% effective rate due 2006		1.2
7.75% due 2007-2008	0.6	0.8
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	
6.50% due 2011	450.0	450.0
6.51% due 2013	30.0	30.0
4.08% variable rate due 2015 (a)	17.4	17.4
3.80% variable rate due 2016 (a)	67.0	67.0
6.94% due 2028	50.0	50.0
3.80% variable rate due 2030 (a)	80.0	80.0
6.20% due 2033	200.0	200.0
Obligations under capital leases	231.4	230.8
Unamortized discount, net and other	(23.9)	(24.7)
Long-term debt due currently	(296.7)	(496.0)
Total Long-Term Debt	3,073.4	3,031.0
Total Capitalization	$ 5,992.8	$ 5,741.5

(a) Variable interest rate as of December 31, 2006.
(b) Variable interest rate as of December 31, 2005.
The accompanying Notes to Consolidated Financial Statements are an integral part of these financial statements.

Table of Contents

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 principal 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.

Our Consolidated Statements of Cash Flows has been modified to present separately cash flows from continuing operations and cash flows from discontinued operations. Previously, we presented cash flows from continuing operations on our Consolidated Statements of Cash Flows and cash flows from discontinued operations were presented separately in the notes to the Financial Statements.

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 purchase 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. In a rate order issued in January 2006, the PSCW approved a plan to refund any over-collected fuel on an annual basis for 2006. For 2007, the band is plus or minus 2%.

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.

Accounting for MISO Energy Transactions: MISO implemented the MISO Midwest Market on April 1, 2005. The MISO Midwest Market operates under both day-ahead and real-time markets. We record energy transactions in the MISO on a net basis for each hour.

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

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	2006	2005	2004
	(Millions of Dollars)		
Capitalized Carrying Costs	$25.0	$20.4	$12.7
AFUDC - Equity	14.6	9.2	2.8
Gross Receipts Tax Recovery	4.0	2.6	1.5
Gain on Sale of Guardian Investment	2.8		
Debt Redemption Costs			(22.9)
Other, net	6.7	(3.5)	(8.4)
Total Other Income and Deductions, net	$53.1	$28.7	($14.3)

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	2006	2005
	(Millions of Dollars)	
Utility Energy	$ 8,781.5	$ 8,311.0
Non-Utility Energy	389.5	389.0
Other	94.4	149.6
Total	$ 9,265.4	$ 8,849.6

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, 2006 and 2005, the net book value of regulated capitalized software totaled $17.8 million and $22.3 million, respectively. The net book value of other capitalized software was approximately $1.7 million and $2.4 million as of December 31, 2006 and 2005, 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 2006, 3.9% in 2005 and 4.0% in 2004. Nuclear plant decommissioning costs are accrued and included in depreciation expense (see Note I). 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. We 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 $630.6 million as of December 31, 2006 and $604.2 million as of December 31,

2005.

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

We recorded the following CWIP by segment at December 31:

	2006	2005
	(Millions of Dollars)	
Utility Energy	$ 103.5	$ 237.7
Non-Utility Energy	865.9	354.5
Other	23.0	4.4
Total	$ 992.4	$ 596.6

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, net.

During 2006, Wisconsin Electric accrued AFUDC at a rate of 8.94%, as authorized by the PSCW. During 2005 and 2004, 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 2006, Wisconsin Gas accrued AFUDC at a rate of 11.31%, as authorized by the PSCW. During 2005 and 2004, the authorized rate was 10.32%. Wisconsin Gas accrued AFUDC on specific large construction projects during 2005 and 2004. During 2006, Wisconsin Gas accrued AFUDC on 50% of CWIP balances.

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

	2006	2005	2004
	(Millions of Dollars)		
AFUDC - Debt	$ 5.2	$ 4.6	$ 1.5
AFUDC - Equity	$ 14.5	$ 9.2	$ 2.8

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.

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

Materials, Supplies and Inventories: Our inventory at December 31 consists of:

Materials, Supplies and Inventories	2006	2005
	(Millions of Dollars)	
Fossil Fuel	$ 121.0	$ 90.4
Natural Gas in Storage	188.6	265.5
Materials and Supplies	107.6	95.7
Total	$ 417.2	$ 451.6

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 in 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. 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 J.

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

We have nuclear decommissioning trusts that hold investments in debt and equity securities. All assets within the nuclear decommissioning trusts are restricted to nuclear decommissioning activities as set forth by regulations promulgated by the IRS and by the PSCW. The accompanying Consolidated Statements of Cash Flows includes proceeds from investments within the nuclear decommissioning trusts and purchases of investments within the nuclear decommissioning trusts.

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.

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

Goodwill and Intangible Assets: We account for goodwill and other intangible assets following SFAS 142, effective January 1, 2002. As of December 31, 2006 and 2005, 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 2006 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, 2006, 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, 2006 and 2005, we had a total ownership interest of approximately 29.4% and 33.5%, 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. All options granted subsequent to December 31, 2004 vest on a cliff-basis after a three year period. Prior to January 1, 2006, we reported benefits of tax deductions in

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

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 new standard and the impacts to our Consolidated Financial Statements, see Note J.

We previously adopted the disclosure provisions of SFAS 123 as amended by SFAS 148. The fair value of our stock options at date of grant for 2006 was calculated using a binomial option-pricing model. For 2005 and 2004, 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	
	2006	2005	2004
Risk free interest rate	4.3% -4.4%	4.4%	4.6%
Dividend yield	2.4%	2.5%	2.5%
Expected volatility	17.0% -20.0%	19.0%	23.1%
Expected life (years)	6.3	10.0	10.0
Pro forma weighted average fair value of our stock options granted	$7.55	$ 8.32	$ 9.45

As described more fully in the following table, our diluted earnings would have been reduced by $0.02 and $0.24 per share, respectively, had we expensed the 2005 and 2004 grants for stock-based compensation plans under SFAS 123. In 2004, the pro forma expense increased, in part, due to the effect of accelerating the vesting of stock options, which resulted in a pro forma expense of $0.16 per share. For further information regarding equity based compensation, see Note J.

	2005	2004
	(Millions of Dollars, Except per share amounts)	
Net Income - as reported	$ 308.7	$ 306.4
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects	2.3	2.5
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	4.5	31.5
Net Income - Pro forma	$ 306.5	$ 277.4
Basic Earnings Per Common Share		
As reported	$ 2.64	$ 2.60
Pro forma	$ 2.62	$ 2.36
Diluted Earnings Per Common Share		
As reported	$ 2.61	$ 2.57
Pro forma	$ 2.59	$ 2.33

Nuclear Fuel Amortization: We amortize our nuclear fuel inventory to fuel expense as the power is generated, generally over a period of 60 months.

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

B RECENT ACCOUNTING PRONOUNCEMENTS

Share Based Compensation: In December 2004, the FASB issued SFAS 123R. In March 2005, the SEC issued SAB 107 regarding the SEC s interpretation of SFAS 123R and the valuation of share-based payment for public companies. This statement requires that the compensation costs relating to such transactions be recognized in the consolidated income statement. We adopted SFAS 123R and SAB 107 effective January 1, 2006 using the modified prospective method. For additional information, see Note J.

Implicit Variable Interests: In April 2006, the FASB issued FSP FIN 46R-6. FSP FIN 46R-6 addresses the requirement to determine the variability to be considered in applying FIN 46R-6 based on an analysis of the design of the entity. As required, we adopted FSP FIN 46R-6 effective July 1, 2006 for any new arrangements entered into after the effective date. For further information, see Note G.

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. SFAS 157 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 are currently evaluating the provisions of SFAS 157 and we expect to adopt SFAS 157 on January 1, 2008.

Pension and Other Post-retirement Plans: In September 2006, the FASB issued SFAS 158, an amendment of SFAS 87, 88, 106 and 132R. SFAS 158 requires recognition of the overfunded or underfunded status of a defined benefit post-retirement plan as an asset or liability on the balance sheet and recognition of changes in that funded status in the year in which the changes occur through comprehensive income. SFAS 158 also requires an employer to measure the funded status of a plan as of the date of its year end balance sheet. We adopted SFAS 158 as of December 31, 2006. For further information, see Note O.

Financial Statement Errors: In September 2006, the SEC staff issued SAB 108. SAB 108 addresses the diversity in practice by registrants when quantifying the effect of an error on the financial statements. SAB 108 provides guidance on the consideration of the effects of prior year misstatements in quantifying current year misstatements. We adopted the provisions of SAB 108 effective December 31, 2006. The adoption of SAB 108 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, 2006, we had approximately $55.0 million of net regulatory assets that were not earning a return.

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

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

	2006	2005
	(Millions of Dollars)	
Regulatory Assets		
Deferred unrecognized pension costs (see Note O)	$ 357.2	$ 377.2
Escrowed electric transmission costs	192.2	169.4
Deferred income tax related	98.3	96.6
Deferred fuel related costs	79.1	72.8
Deferred plant related - capital lease (see Note K)	71.8	67.0
Deferred unrecognized OPEB costs (see Note O)	70.5	17.3
Deferred environmental costs	68.2	64.2
Escrowed bad debt costs	57.0	58.1
Escrowed unrecovered plant costs	31.6	56.5
Other, net	65.1	46.5
Total long-term regulatory assets	$ 1,091.0	$ 1,025.6
Regulatory Liabilities		
Deferred cost of removal obligations (see Notes F and I)	$ 630.6	$ 604.2
Deferred asset retirement obligations (see Notes F and I)	537.1	475.3
Deferred pension benefit	62.3	71.0
Deferred income tax related	95.4	103.8
Other, net	146.7	118.9
Total long-term regulatory liabilities	$ 1,472.1	$ 1,373.2
Net long-term regulatory liabilities	$ 381.1	$ 347.6

As of December 31, 2005, we recorded a minimum pension liability to reflect the funded status of our pension plans (see Note O). 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).

In October 2002, the PSCW issued an order authorizing Wisconsin Electric to implement a surcharge for recovery of annual electric transmission costs projected through 2005. In addition, the PSCW order authorized escrow accounting treatment for transmission costs.

As of December 31, 2006, we have deferred $79.1 million of fuel related costs. The majority of these deferred costs were incurred in 2005 as a result of an extended outage at Point Beach, increased costs associated with reduced coal deliveries due to a railroad transportation problem and increased costs associated with the MISO Midwest Market.

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, 2006, we have recorded $68.2 million of environmental costs associated with manufactured gas plant sites as a regulatory asset, including $37.7 million of deferrals for actual remediation costs incurred and a $30.5 million accrual for estimated future site remediation (See Note S). In addition, we have deferred $8.8 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 part of our PTF strategy, the PSCW approved the retirement and removal of the Port Washington Power Plant coal units to make way for construction of gas-fired facilities. In a September 27, 2003 order, the PSCW authorized transferring the undepreciated costs and related removal amounts to a regulatory asset account. The escrowed unrecovered plant costs totaled $31.6 million at December 31, 2006.

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont'd)

As of December 31, 2006, we have $57.0 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, and that treatment continued through 2006.

In connection with the WICOR acquisition, we recorded the funded status of the Wisconsin Gas pension and post-retirement medical plans at fair value at the acquisition date. Due to the expected regulatory treatment of these items, we record a regulatory liability (Deferred pension) that is being amortized over an average remaining service life of 15 years ending 2015.

D ASSET SALES, DIVESTITURES AND DISCONTINUED OPERATIONS

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 had been 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. Previously, in the third quarter of 2004, we concluded the asset was impaired and recorded a non-cash asset valuation charge of $27.0 million ($17.6 million after 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. In the third quarter of 2004, we concluded that this asset was impaired and recorded a non-cash asset valuation charge of $122.0 million ($79.3 million after tax).

Manufacturing Segment: Effective July 31, 2004, we sold WICOR, Inc. to Pentair, Inc. and received cash proceeds of $857 million, and Pentair, Inc. assumed approximately $25 million of third party debt.

WICOR s only asset at the time of the sale consisted of its interest in WICOR Industries. As a condition of the sale, WICOR transferred its ownership of Wisconsin Gas to Wisconsin Energy through a stock redemption. Prior to the transaction, Wisconsin Gas converted from a corporation to a limited liability company (collectively the Wisconsin Gas transfer). We expect the final determination of cash taxes to be approximately $105 million as a result of the stock redemption described above. However, we also expect to receive future tax deductions from a step-up in the tax basis of the Wisconsin Gas assets as a result of the Wisconsin Gas transfer. We therefore expect that substantially all of the cash taxes paid on the stock redemption will be recovered as deferred income tax assets through future deductions.

In accordance with SFAS 144, we have reclassified the assets and liabilities of Minergy Neenah as Assets held for sale in the accompanying Consolidated Balance Sheets. Total assets held for sale for Minergy Neenah were $17.4 million at December 31, 2005. In addition, we have recorded the operating results of Minergy Neenah, Calumet and the Manufacturing Segment as Income from Discontinued Operations, Net of Tax in the accompanying Consolidated Income Statements for the years ended December 31, 2006, 2005 and 2004. Previously, Minergy Neenah s results were included in corporate and other and the Calumet operations were included in the non-utility energy segment. See below for a summary of the components of Discontinued Operations in our Consolidated Income Statements.

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont d)

	Year End December 31		
	2006 (a)	**2005 (b)**	**2004 (c)**
	(Millions of Dollars)		
Operating Revenues			
Manufacturing Segment	$	$	$ 481.0
Calumet		2.3	5.2
Minergy Neenah	14.3	18.1	19.8
Total	$ 14.3	$ 20.4	$ 506.0
Income (Loss) Before Income Taxes			
Manufacturing Segment	$	$	$ 50.9
Calumet		0.4	(125.0)
Minergy Neenah	2.4	(6.4)	(24.9)
Total	$ 2.4	($ 6.0)	($ 99.0)
Gain (Loss) on Sale After-Tax			
Manufacturing Segment	$ 2.4	$	$ 152.3
Calumet		4.7	
Minergy Neenah (d)	(0.4)		
Total	$ 2.0	$ 4.7	$ 152.3

(a) Includes the results of Minergy through September 27, 2006.
(b) Includes the results of Calumet through May 31, 2005.
(c) Includes the results of our manufacturing segment through July 31, 2004.
(d) 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.

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, including fuel, 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.

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont d)

Cash Flows: The following table identifies key pre-tax cash outflows and inflows related to the construction of our PTF units for the twelve months ended December 31, 2006 and 2005 and compares it to total WEC.

Capital Expenditures (Millions of Dollars)	PWGS 1	PWGS 2	OC 1	OC 2	Total PTF	Total WEC
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)	PWGS 1	PWGS 2	OC 1	OC 2	Total PTF	Total WEC
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)	PWGS 1	PWGS 2	OC 1	OC 2	Total PTF	Total WEC
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 (approximately 14%). 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 as of December 31, 2006 and 2005:

CWIP - Cash Expenditures (Millions of Dollars)	PWGS 1	PWGS 2	OC 1	OC 2	Total PTF
December 31, 2006	$	$ 196.2	$ 487.7	$ 152.6	$ 836.5
December 31, 2005	$	$ 67.5	$ 198.9	$ 74.9	$ 341.3

Total CWIP (Millions of Dollars)	PWGS 1	PWGS 2	OC 1	OC 2	Total PTF	Total WEC
December 31, 2006	$	$ 207.7	$ 517.3	$ 163.5	$ 888.5	$ 992.4
December 31, 2005	$	$ 70.7	$ 209.2	$ 78.9	$ 358.8	$ 596.6

Net Plant in Service (Millions of Dollars)	PWGS 1	PWGS 2	OC 1	OC 2	Total PTF	Total WEC
December 31, 2006	$ 350.1	$	$	$	$ 350.1	$ 5,841.7
December 31, 2005	$ 359.9	$	$	$	$ 359.9	$ 5,561.1

Deferred Revenue Included in Other Long-term Liabilities (Millions of Dollars)	PWGS 1	PWGS 2	OC 1	OC 2	Total PTF	Total WEC
December 31, 2006	$ 68.3	$ 27.5	$ 66.0	$ 24.4	$ 186.2	$ 186.2
December 31, 2005	$ 71.2	$ 8.5	$ 20.6	$ 8.5	$ 108.8	$ 108.8

Income Statement: Once the PTF units are placed in service, we will 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

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont d)

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 will include the amortization of the deferred revenues that reflect the carrying costs that are collected during construction. The deferred revenue will be amortized on a straight line basis over the lease term. We will 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.

F ASSET RETIREMENT OBLIGATIONS

The following table presents the change in our asset retirement obligations during 2006.

	Balance at December 31, 2005	Liabilities Incurred	Liabilities Settled	Accretion	Balance at December 31, 2006
			(Millions of Dollars)		
Asset Retirement Obligations	$355.5	$	($2.1)	$18.3	$371.7

SFAS 143 primarily applies to the future decommissioning costs for Point Beach. Prior to January 2003, we recorded a long-term liability for accrued nuclear decommissioning costs. See Note I for further information about the nuclear decommissioning of Point Beach, including our investments in nuclear decommissioning trusts that are restricted to nuclear decommissioning.

In March 2005, the FASB issued FIN 47. FIN 47 defines a conditional asset retirement obligation 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 asset retirement obligations related to asbestos removal costs.

The adoption of FIN 47 had no impact on our net income in 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 asset retirement obligations 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 $603.0 million of required payments over the remaining term of these three agreements,

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont d)

which expire over the next 16 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	2006	2005	2004
	(Millions of Dollars)		
Current tax expense	$ 229.0	$ 63.7	$ 126.3
Deferred income taxes, net	(49.7)	90.2	11.3
Investment tax credit, net	(4.3)	(4.7)	(4.8)
Total Income Tax Expense	$ 175.0	$ 149.2	$ 132.8

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:

	2006		2005		2004	
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	$ 170.6	35.0%	$ 158.5	35.0%	$ 123.4	35.0%
State income taxes net of federal tax benefit	24.1	4.9%	21.2	4.7%	20.2	5.7%
Reversal of valuation allowances	(5.8)	(1.1%)	(16.3)	(3.6%)		%
Investment tax credit restored	(4.3)	(0.9%)	(4.7)	(1.0%)	(4.8)	(1.4%)
Other, net	(9.6)	(2.0%)	(9.5)	(2.1%)	(6.0)	(1.6%)
Total Income Tax Expense	$ 175.0	35.9%	$ 149.2	33.0%	$ 132.8	37.7%

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont d)

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

	2006	2005
	(Millions of Dollars)	
Deferred Tax Assets		
Current		
Employee benefits and compensation	$ 13.9	$ 13.8
Recoverable gas costs	9.0	3.3
Other	3.8	5.8
Total Current Deferred Tax Assets	$ 26.7	$ 22.9
Non-current		
Employee benefits and compensation	$ 110.4	$ 117.3
Decommissioning trust	98.1	85.8
Construction advances	84.8	71.6
Property-related	73.2	45.5
Deferred revenues	84.4	28.4
State NOL s	29.2	28.0
Valuation allowance	(3.4)	(11.8)
Emission allowances	19.0	18.4
Other	38.3	34.9
Total Non-current Deferred Tax Assets	$ 534.0	$ 418.1
Total Deferred Tax Assets	$ 560.7	$ 441.0
Deferred Tax Liabilities		
Current		
Prepaid items	$ 39.1	$ 33.2
Uncollectible account expense	9.1	8.8
Total Current Deferred Tax Liabilities	$ 48.2	$ 42.0
Non-current		
Property-related	$ 848.5	$ 792.0
Employee benefits and compensation	71.8	68.8
Deferred transmission costs	76.5	64.6
Investment in transmission affiliate	44.3	40.4
Other	65.8	46.0
Total Non-current Deferred Tax Liabilities	$ 1,106.9	$ 1,011.8
Total Deferred Tax Liabilities	$ 1,155.1	$ 1,053.8

Consolidated Balance Sheet Presentation	**2006**	**2005**

Current Deferred Tax Asset (Liability)	($ 21.5)	($ 19.1)
Non-current Deferred Tax Asset (Liability)	($ 572.9)	($ 593.7)

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, 2006 and 2005, we had recorded $3.4 million and $11.8 million of valuation allowances primarily related to the uncertainty of our ability to benefit from state loss carryforwards in the future. In connection with the favorable decision by the Supreme Court of Wisconsin in June 2005 to uphold the CPCN granted by the PSCW for the construction of the Oak Creek expansion, we have concluded that it is 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

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont d)

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.

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. FIN 48 provides clarification on the accounting for income taxes by setting forth a minimum recognition threshold an uncertain tax position is required to meet before being recognized in the financial statements. FIN 48 also provides guidance on de-recognition, measurement, classification, interest and penalties, accounting in interim periods, disclosure and transition. FIN 48 is effective for fiscal years beginning after December 15, 2006. We adopted FIN 48 effective January 1, 2007. As a result of the adoption of FIN 48, we estimate that the cumulative effect on retained earnings is immaterial.

I NUCLEAR OPERATIONS

Point Beach Nuclear Plant: We own two 518 MW electric generating units at Point Beach in Two Rivers, Wisconsin. NMC operates the units on our behalf. The units were placed in service in the early 1970 s and the original operating licenses were effective through 2010 and 2013. In December 2005, the NRC renewed the operating licenses through October 2030 for Unit 1 and March 2033 for Unit 2.

Proposed Sale of Point Beach: In December 2006, we announced that Wisconsin Electric signed a definitive agreement with an affiliate of FPL to sell Point Beach for approximately $998 million, subject to closing price adjustments. Under the terms of the sale, the buyer would assume the obligation to decommission the plant, and we would transfer assets in a qualified trust for decommissioning. We would retain assets in a non-qualified decommissioning trust. Wisconsin Electric also entered into a long-term power purchase agreement to purchase all of the existing capacity and energy of the plant, which will become effective upon closing of the sale. Wisconsin Electric will have the unilateral option, subject to PSCW direction, to select a term for the power purchase agreement of either (i) an estimated 23 years for Unit 1 and 26 years for Unit 2, or (ii) 16 years for Unit 1 and 17 years for Unit 2. The sale of the plant and the long-term power purchase agreement are subject to review and approval by various regulatory agencies including the NRC, PSCW, MPSC and FERC. We anticipate closing the sale during the third quarter of 2007. We have submitted a request to the PSCW to defer any gain (net of transaction related costs) as a regulatory liability that would be applied to the benefit of our customers in future rate proceedings.

Nuclear Insurance: The Price-Anderson Act currently limits the total public liability for damages arising from a nuclear incident at a nuclear power plant to approximately $10.8 billion, of which $300 million is covered by liability insurance purchased from private sources. The remaining $10.5 billion is covered by an industry retrospective loss sharing plan whereby, in the event of a nuclear incident resulting in damages exceeding the private insurance coverage, each owner of a nuclear plant would be assessed a deferred premium of up to $100.6 million per reactor with a limit of $15 million per reactor within one calendar year. We have two reactors. We are obligated to pay our proportionate share of any such assessment as long as we own Point Beach.

Wisconsin Electric, through its membership in NEIL, carries decontamination, property damage and decommissioning shortfall insurance covering losses of up to $2.1 billion at Point Beach. Under policies issued by NEIL, the insured member may be liable for a retrospective premium in the event of catastrophic losses exceeding the full financial resources of NEIL. Wisconsin Electric s maximum retrospective liability under the above policies is $17.8 million.

Wisconsin Electric also maintains insurance with NEIL through which it can recover up to $3.5 million per week, subject to a total limit of $490 million, during any prolonged outage at Point Beach caused by accidental property damage. Wisconsin Electric s maximum retrospective liability under this policy is $9.8 million.

It should not be assumed that, in the event of a major nuclear incident, any insurance or statutory limitation of liability would protect Wisconsin Electric from material adverse impact.

Nuclear Decommissioning: We record decommissioning expense in amounts equal to the amounts collected in rates and funded to the external trusts. Nuclear decommissioning costs are accrued over the expected service lives

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont d)

of the nuclear generating units and are included in electric rates. Decommissioning funding was $17.6 million for each of the years ended 2006, 2005 and 2004. As of December 31, 2006, our non-qualified investments were $303.7 million and our qualified investments were $577.9 million. We had the following investments in Nuclear Decommissioning Trusts, stated at fair value as of December 31, 2006 and 2005:

	2006	2005
	(Millions of Dollars)	
Funding and Realized Earnings	$ 607.2	$ 566.6
Unrealized Gains	274.4	215.5
Total Investments	$ 881.6	$ 782.1

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 are classified as available for sale. Gains and losses on the fund are determined on the basis of specific identification; net unrealized gains on the fund are recorded as part of the fund. Our investments in the trusts are recorded at fair value and we are allowed regulatory treatment for the fair value adjustment. Realized gains and losses for the years ended December 31, 2006 and 2005 were as follows:

	2006	2005
	(Millions of Dollars)	
Realized Gains	$ 21.2	$ 19.1
Realized (Losses)	(10.6)	(9.1)
Net Realized Gain	$ 10.6	$ 10.0

Total gains and total losses by security type for the years ended December 31, 2006 and 2005 were as follows:

December 31, 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

December 31, 2005	Total Gains	Total (Losses)	Net Gain (Loss)
Debt	$2.1	($5.0)	($2.9)
Equity	236.5	(8.1)	228.4
Total	$238.6	($13.1)	$225.5

The contractual maturities of debt securities at December 31, 2006 are as follows: $14.8 million in 2007; $52.0 million in 2008-2011; $97.9 million in 2012-2016; and $125.2 million thereafter.

The PSCW requires us to perform periodic Decommissioning Cost Studies to evaluate the funded status of our Nuclear Decommissioning Trusts as compared with the estimated costs to perform the decommissioning work. In June 2005, we filed a new Decommissioning Cost Study with the PSCW. The study was performed by an outside consultant and it included several assumptions as to the timing and scope of the decommissioning work. This study estimated that the cost to decommission the plant would be $712.5 million in 2004 dollars. A prior study had estimated the cost to be $1.1 billion in 2003 dollars. The reduction in the estimated cost to decommission the plant was driven by several factors, including the timing and the scope of the work to be performed.

The June 2005 Decommissioning Cost Study was also used to estimate our ARO for nuclear decommissioning. We record an ARO for future decommissioning costs based upon the net present value of the expected cash flows

Table of Contents

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Cont d)

associated with our legal obligation to decommission our plants. Under SFAS 143, certain costs included in the June 2005 Decommissioning Cost Study that related to fuel management and non-nuclear demolition were excluded from the ARO calculation. Using the June 2005 study, our estimated costs for decommissioning, following SFAS 143, were $473.2 million. Our ARO for nuclear decommissioning as of December 31, 2006 was $325.6 million.

We recover decommissioning costs in our regulated rates. We have established a regulatory liability to reflect the difference between nuclear decommissioning costs recovered in rates and cumulative investment gains (our nuclear decommissioning trust investments) in comparison to the ARO for nuclear decommissioning that is calculated under SFAS 143. For further information on AROs, see Note F.

The ultimate timing and amount of future cash flows associated with nuclear decommissioning is dependent upon many significant variables including the scope of work involved, the ability to relicense the plants in the future, future inflation rates and discount rates. Because of our announced agreement to sell Point Beach to an affiliate of FPL, we do not expect to remain obligated to decommission Point Beach if the sale is consummated. However, if that sale is not completed, based on the license renewal received by the NRC in December 2005, we do not expect to make any significant nuclear decommissioning expenditures before the year 2030.

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 will be amortized to nuclear fuel expense and included in utility rates through September 2007.

J COMMON EQUITY

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. All share-based compensation is fulfilled by purchases on the open market and do not dilute shareholders ownership.

The following is a summary of our stock options issued through December 31, 2006:

	2006		2005		2004	
Stock Options	**Number of Options**	**Weighted-Average Exercise Price**	**Number of Options**	**Weighted-Average Exercise Price**	**Number of Options**	**Weighted-Average Exercise Price**
Outstanding at January 1	7,569,619	$				