WISCONSIN ENERGY CORP
Form 10-K
February 27, 2013

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, 2012

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

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

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

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

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T

(§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).   Yes [X]   No [ ]

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

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

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

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

The aggregate market value of the common stock of Wisconsin Energy Corporation held by non-affiliates was approximately $9.1 billion based upon the reported closing price of such securities as of June 30, 2012.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date (January 31, 2013):

Common Stock, $.01 Par Value,	229,005,057 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 2, 2013, are incorporated by reference into Part III hereof.

WISCONSIN ENERGY CORPORATION
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DEFINITION OF ABBREVIATIONS AND INDUSTRY TERMS

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

Primary Subsidiaries	
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
PIPP	Presque Isle Power Plant
PSGS	Paris Generating Station
PWGS	Port Washington Generating Station
PWGS 1	Port Washington Generating Station Unit 1
PWGS 2	Port Washington Generating Station Unit 2
VAPP	Valley Power Plant
Other Subsidiaries and Affiliates	
ATC	American Transmission Company LLC
ERGSS	Elm Road Generating Station Supercritical, LLC
Minergy	Minergy LLC
WECC	Wisconsin Energy Capital Corporation
Wispark	Wispark LLC
Wisvest	Wisvest LLC
Federal and State Regulatory Agencies	
CFTC	Commodity Futures Trading Commission
DOE	United States Department of Energy
DOJ	Wisconsin Department of Justice
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
IRS	Internal Revenue Service
MPSC	Michigan Public Service 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
BART	Best Available Retrofit Technology
BTA	Best Technology Available
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CO_2	Carbon Dioxide
CSAPR	Cross-State Air Pollution Rule
MATS	Mercury and Air Toxics Standards

NAAQS	National Ambient Air Quality Standards

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:

NOV	Notice of Violation
NO_x	Nitrogen Oxide
$PM_{2.5}$	Fine Particulate Matter
RACT	Reasonably Available Control Technology
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
Other Terms and Abbreviations	
AQCS	Air Quality Control System
ARRs	Auction Revenue Rights
Bechtel	Bechtel Power Corporation
Compensation Committee	Compensation Committee of the Board of Directors
CPCN	Certificate of Public Convenience and Necessity
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
Edison Sault	Edison Sault Electric Company
ERISA	Employee Retirement Income Security Act of 1974
Exchange Act	Securities Exchange Act of 1934, as amended
Fitch	Fitch Ratings
FTRs	Financial Transmission Rights
GCRM	Gas Cost Recovery Mechanism
Junior Notes	Wisconsin Energy's 2007 Series A Junior Subordinated Notes due 2067
LMP	Locational Marginal Price
MISO	Midwest Independent Transmission System Operator, Inc.
MISO Energy Markets	MISO Energy and Operating Reserves Market
Montfort	Montfort Wind Energy Center
Moody's	Moody's Investor Service
NDAA	National Defense Authorization Act
NYMEX	New York Mercantile Exchange
OTC	Over-the-Counter
Plan	The Wisconsin Energy Corporation Retirement Account Plan
Point Beach	Point Beach Nuclear Power Plant
PTF	Power the Future
PUHCA 2005	Public Utility Holding Company Act of 2005
RCC	Replacement Capital Covenant dated May 11, 2007
RTO	Regional Transmission Organization
Settlement Agreement	Settlement Agreement and Release between Elm Road Services, LLC and Bechtel effective as of December 16, 2009
S&P	Standard & Poor's Ratings Services
WPL	Wisconsin Power and Light Company, a subsidiary of Alliant Energy Corp.
Wolverine	Wolverine Power Supply Cooperative, Inc.
Measurements	
Btu	British Thermal Unit(s)
Dth	Dekatherm(s) (One Dth equals one million Btu)

kW	Kilowatt(s) (One kW equals one thousand Watts)

DEFINITION OF ABBREVIATIONS AND INDUSTRY TERMS

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

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
ARO	Asset Retirement Obligation
ASU	Accounting Standards Update
CWIP	Construction Work in Progress
FASB	Financial Accounting Standards Board
GAAP	Generally Accepted Accounting Principles
IFRS	International Financial Reporting Standards
OPEB	Other Post-Retirement Employee Benefits

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

Certain statements contained in this report are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934, as amended (Exchange Act). These statements are based upon management's current expectations and are subject to risks and uncertainties that could cause our actual results to differ materially from those contemplated in the statements. Readers are cautioned not to place undue reliance on these forward-looking statements. Forward-looking statements include, among other things, statements concerning management's expectations and projections regarding earnings, completion of construction projects, regulatory matters, on-going legal proceedings, fuel costs, sources of electric energy supply, coal and gas deliveries, remediation costs, environmental and other capital expenditures, liquidity and capital resources and other matters. In some cases, forward-looking statements may be identified by reference to a future period or periods or by the use of forward-looking terminology such as "anticipates," "believes," "estimates," "expects," "forecasts," "goals," "guidance," "intends," "may," "objectives," "plans," "possible," "potential," "projects," "seeks," "should," "targets" 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 catastrophic weather-related or terrorism-related damage; cyber-security threats and disruptions to our technology network; availability of electric generating facilities; unscheduled generation outages, or unplanned maintenance or repairs; unanticipated events causing scheduled generation outages to last longer than expected; unanticipated changes in fossil fuel, purchased power, coal supply, gas supply or water supply costs or availability due to higher demand, shortages, transportation problems or other developments; unanticipated changes in the cost or availability of materials needed to operate new environmental controls at our electric generating facilities or replace and/or repair our electric and gas distribution systems; nonperformance by electric energy or natural gas suppliers under existing power purchase or gas supply contracts; environmental incidents; electric transmission or gas pipeline system constraints; unanticipated organizational structure or key personnel changes; collective bargaining agreements with union employees or work stoppages; or inflation rates.

- Factors affecting the demand for electricity and natural gas, including weather and other natural phenomena; the economic climate in our service territories; customer growth and declines; customer business conditions, including demand for their products and services; and energy conservation efforts.

- Timing, resolution and impact of future rate cases and negotiations, including recovery of costs associated with environmental compliance, renewable generation, transmission service, distribution system upgrades, fuel and the Midwest Independent Transmission System Operator, Inc. (MISO) Energy Markets.

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

- The ability to control costs and avoid construction delays during the development and construction of new environmental controls and renewable generation, as well as upgrades to our electric and natural gas distribution systems.

- The impact of recent and future federal, state and local legislative and regulatory changes, including any changes in rate-setting policies or procedures; electric and gas industry restructuring initiatives; transmission or distribution system operation and/or administration initiatives; any required changes in facilities or operations to reduce the risks or impacts of potential terrorist activities or cybersecurity threats; required approvals for new construction, and the siting approval process for new generation and transmission facilities and new pipeline construction; changes to the Federal Power Act and related regulations and enforcement thereof by the Federal Energy Regulatory Commission (FERC) and other regulatory agencies; changes in allocation of energy assistance, including state public benefits funds; changes in environmental, tax and other laws and regulations to which we are subject; changes in the application of existing laws and regulations; and changes in the interpretation or enforcement of permit conditions by the permitting agencies.

- 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.

- Current and future litigation, regulatory investigations, proceedings or inquiries, including FERC matters and Internal Revenue Service (IRS) audits and other tax matters.

- Events in the global credit markets that may affect the availability and cost of capital.

- Other factors affecting our ability to access the capital markets, including general capital market conditions; our capitalization structure; market perceptions of the utility industry, us or any of our subsidiaries; and our credit ratings.

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

- The financial performance of American Transmission Company LLC (ATC) and its corresponding contribution to our earnings.

- The impact of the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) and any regulations promulgated thereunder, including rules recently adopted and/or proposed by the Commodity Futures Trading Commission (CFTC) that may impact our hedging activities and related costs.

- The impact of the Patient Protection and Affordable Care Act and the Health Care and Education Reconciliation Act of 2010 and any related regulations.

- The effect of accounting pronouncements issued periodically by standard setting bodies, including any changes in regulatory accounting policies and practices and any requirement for U.S. registrants to follow International Financial Reporting Standards (IFRS) instead of Generally Accepted Accounting Principles (GAAP).

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

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

- The ability to obtain and retain short- and long-term contracts with wholesale customers.

- Potential strategic business opportunities, including acquisitions and/or dispositions of assets or businesses, which we cannot ensure will be beneficial for us.

- Incidents affecting the U.S. electric grid or operation of generating facilities.

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

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

- Foreign governmental, economic, political and currency risks.

- Other business or investment considerations that may be disclosed from time to time in our Securities and Exchange Commission (SEC) filings or in other publicly disseminated written documents, including the risk factors set forth in

Item 1A of this report.

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.

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 reportable segments: a utility energy segment and a non-utility energy segment. Our primary subsidiaries are Wisconsin Electric Power Company (Wisconsin Electric), Wisconsin Gas LLC (Wisconsin Gas) and W.E. Power, LLC (We Power).

Utility Energy Segment: Our utility energy segment consists of Wisconsin Electric and Wisconsin Gas, operating together under the trade name of "We Energies." We Energies serves approximately 1,125,700 electric customers in Wisconsin and the Upper Peninsula of Michigan. We Energies serves approximately 1,074,000 gas customers in Wisconsin and approximately 460 steam customers in metropolitan Milwaukee, Wisconsin.

Non-Utility Energy Segment: Our non-utility energy segment consists primarily of We Power, which owns and leases to Wisconsin Electric generation plants constructed as part of our PTF strategy. All four of the plants constructed as part of Power the Future (PTF) have been placed in service. Port Washington Generating Station Unit 1 (PWGS 1) and Port Washington Generating Station Unit 2 (PWGS 2) are being leased to Wisconsin Electric under long-term leases that run for 25 years. Oak Creek expansion Unit 1 (OC 1) and Oak Creek expansion Unit 2 (OC 2) are being leased to Wisconsin Electric under long-term leases that run for 30 years.

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

Our annual and periodical filings with 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. Wisconsin Electric, which is the largest electric utility in the state of Wisconsin, generates and distributes electric energy in a territory that includes southeastern (including the metropolitan Milwaukee area), east central and northern Wisconsin and the Upper Peninsula of Michigan.

Wisconsin Electric participates in the MISO Energy Markets. The competitiveness of our generation offered in the MISO Energy Markets affects how our generating units are dispatched and how we buy and sell power. For further information, see Factors Affecting Results, Liquidity and Capital Resources in Item 7.

Electric Sales

Our electric energy sales to all classes of customers totaled approximately 30.3 million MWh during 2012 and approximately 31.3 million MWh during 2011. We had approximately 1,125,700 electric customers as of December 31, 2012 and 1,122,500 electric customers as of December 31, 2011.

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

Electric Sales Growth: Our service territory experienced flat sales in 2012 as positive customer growth was offset by reduced use per customer. Our weather normalized 2012 retail electric sales, excluding our two largest customers (two iron ore mines) and two large industrial customers that switched to self-generation, were almost equal to our normalized 2011 electric sales. Assuming continuing improvement in the economy over the five-year forecast horizon, we presently anticipate that total retail electric kWh sales and the associated peak electric demand will grow at annual rates of 0.5% to 1.0% over the next five years (excluding sales to the two iron ore mines). These estimates assume normal weather.

Sales to Large Electric Retail Customers: We provide 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.

Our largest retail electric customers are two iron ore mines located in the Upper Peninsula of Michigan. The combined electric energy sales to the two mines accounted for 6.6% and 7.1% of our total electric utility energy sales during 2012 and 2011, respectively. The mines have notified us that they expect production at one of the mines to be reduced in 2013.

Sales to Wholesale Customers: During 2012, we sold wholesale electric energy to one municipally owned system, two rural cooperatives and two municipal joint action agencies located in the states of Wisconsin and Michigan. Our wholesale electric energy sales were also made to 16 other public utilities and power marketers throughout the region under rates approved by FERC. Wholesale sales accounted for approximately 10.6% of our total electric energy sales and 6.2% of total electric operating revenues during 2012, compared with 13.1% of total electric energy sales and 7.0% of total electric operating revenues during 2011.

Electric System Reliability Matters: Our electric sales are impacted by seasonal factors and varying weather conditions. We sell more electricity during the summer months because of the residential cooling load. The Public Service Commission of Wisconsin (PSCW) has planning reserve requirements consistent with the MISO calculated planning reserve margin. The Michigan Public Service Commission (MPSC) has not yet established guidelines in this area. In accordance with the MISO calculated planning reserve margin requirements, we had adequate capacity to meet all of our firm electric load obligations during 2012 and expect to have adequate capacity to meet all of our firm obligations during 2013. For additional information, see Factors Affecting Results, Liquidity and Capital Resources in Item 7.

Competition

The regulated energy industry continues to experience significant structural changes. Increased competition in the retail and wholesale markets may result from restructuring efforts. It is uncertain when, if ever, retail access might be implemented in Wisconsin. Michigan has adopted retail choice which allows customers to remain with their regulated utility at regulated rates or choose an alternative electric supplier to provide power supply service. We continue providing distribution and customer service functions regardless of the customer's power supplier. Although competition and customer switching to alternative suppliers in our service territories in Michigan has been limited, the additional competitive pressures resulting from retail access could lead to a loss of customers.

Electric Supply

Our electric supply strategy is to provide our customers with energy from plants using a diverse fuel mix that is expected to maintain a stable, reliable and affordable supply of electricity. We supply a significant amount of electricity to our customers from power plants that we own. We supplement our internally generated power supply with long-term power purchase agreements, including the Point Beach Nuclear Power Plant (Point Beach) power purchase agreement discussed later in this report, and through spot purchases in the MISO Energy Markets.

Our dependable capability by fuel type as of December 31 is shown below:

	Dependable Capability in MW (a)		
	2012	2011	2010
Coal (b)	3,828	3,904	3,671
Natural Gas - Combined Cycle	1,090	1,090	1,090
Natural Gas/Oil - Peaking Units (c)	962	967	1,005
Renewables (d)	107	80	83
Total	5,987	6,041	5,849

(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 tests and may change slightly from year to year.

(b) The increase in 2011 as compared to 2010 reflects the January 2011 in-service date of OC 2, partially offset by the March 2011 sale of our interest in Edgewater Generating Unit 5. Our share of the dependable capability of OC 2 is 528 MW.

(c) The dual-fueled facilities generally burn oil only if natural gas is not available due to constraints on the natural gas pipeline and/or at the local gas distribution company that delivers gas to the plants.

(d) Includes hydroelectric and wind generation.

The table below indicates our sources of electric energy supply as a percentage of sales for the three years ended December 31, 2012, as well as an estimate for 2013:

	Estimate 2013		Actual 2012		2011		2010	
Coal	56.0	%	43.0	%	54.2	%	53.9	%
Natural Gas - Combined Cycle	7.5	%	15.9	%	6.6	%	8.4	%
Wind	2.3	%	2.3	%	1.0	%	1.0	%
Hydroelectric	1.1	%	0.7	%	1.0	%	1.0	%
Natural Gas/Oil-Peaking Units	0.1	%	0.7	%	0.1	%	0.3	%
Biomass	0.1	%	—	%	—	%	—	%
Net Generation	67.1	%	62.6	%	62.9	%	64.6	%
Purchased Power	32.9	%	37.4	%	37.1	%	35.4	%
Total	100.0	%	100.0	%	100.0	%	100.0	%

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

	2012	2011	2010
Coal	$30.71	$29.78	$26.44
Natural Gas - Combined Cycle	$23.62	$38.02	$43.14
Natural Gas/Oil - Peaking Units	$53.40	$119.83	$97.36
Purchased Power	$41.92	$42.79	$43.11

Historically, coal has been purchased under long-term contracts, which helped with price stability. Coal and associated transportation services have continued to see volatility in pricing due to increased domestic and world-wide demand for coal and the impacts of diesel costs which are incorporated into fuel surcharges on rail transportation.

Natural gas costs have been volatile. We have a PSCW-approved hedging program to help manage our natural gas price risk. This hedging program is generally implemented on a 36-month forward-looking basis. Proceeds related to the natural gas hedging program are reflected in the average costs of natural gas and purchased power shown above.

Coal-Fired Generation

Coal Supply: We diversify the coal supply for our power plants by purchasing coal from mines in Wyoming, Pennsylvania and Montana, as well as from various other states. During 2013, 90% of our projected coal requirements of 10.7 million tons are under contracts which are not tied to 2013 market pricing fluctuations. At the end of 2012, our coal-fired generation consisted of six operating plants with a dependable capability of approximately 3,828 MW.

The annual tonnage amounts contracted for 2013 through 2015 are as follows:

Year	Annual Tonnage (Thousands)
2013	9,586
2014	5,753
2015	4,000

Coal Deliveries: All of our 2013 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 and Pleasant Prairie Power Plants from Wyoming mines, and transport coal for the Oak Creek expansion units from Pennsylvania and Wyoming. Coal from a Montana mine is also transported via rail to Lake Michigan transfer docks and delivered by lake vessel to the Milwaukee harbor for Milwaukee-based power plants. Montana and Wyoming coal for the Presque Isle Power Plant is transported via rail to Superior, Wisconsin, placed in dock storage and reloaded into lake vessels for plant delivery.

Certain of our coal transportation contracts contain fuel cost adjustments that are tied to changes in diesel fuel and crude oil prices. Currently, diesel fuel contracts are not actively traded; therefore, we use financial heating oil contracts to mitigate risk related to diesel fuel prices. We have a PSCW-approved hedging program that allows us to hedge up to 75% of our potential risks related to fuel surcharge exposure. The costs of this program are included in our fuel and purchased power costs.

Edgewater Generating Unit 5: On March 1, 2011, we sold our 25% interest in Edgewater Generating Unit 5 to Wisconsin Power and Light Company, a subsidiary of Alliant Energy Corp. (WPL), for our net book value, including working capital, of approximately $38 million.

Wolverine Joint Ownership Agreement: In November 2012, we entered into a joint ownership agreement with Wolverine Power Supply Cooperative, Inc. (Wolverine) regarding the Presque Isle Power Plant (PIPP), whereby Wolverine will pay for the installation of environmental controls at the plant and will receive a minority ownership interest in the plant in return. We will continue to operate the plant. The transaction and the environmental controls to be installed will require approvals from various state and federal agencies, including the PSCW, the MPSC, the Michigan Department of Environmental Quality and the FERC.

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

Natural Gas-Fired Generation

Our natural gas-fired generation consists of four operating plants with a dependable capability of approximately 1,872 MW as of December 31, 2012.

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.

We have a PSCW-approved hedging program that allows us to hedge up to 65% of our estimated gas usage for electric generation in order to help manage our natural gas price risk. The costs of this program are included in our fuel and purchased power costs.

Oil-Fired Generation

Fuel oil is used for the combustion turbines at the Germantown Power Plant units 1-4, boiler ignition and flame stabilization at the Presque Isle Power Plant, and diesel engines at the Pleasant Prairie Power Plant and Valley Power Plant (VAPP). Our oil-fired generation had a dependable capability of approximately 180 MW as of December 31, 2012. Our natural gas-fired peaking units have the ability to burn oil if natural gas is not available due to delivery constraints. Fuel oil requirements are purchased under agreements with suppliers.

Renewable Generation

Hydroelectric: Wisconsin Electric's hydroelectric generating system consists of 13 operating plants with a total installed capacity of approximately 88 MW and a dependable capability of approximately 40 MW as of December 31, 2012. Of these plants, 12 plants (86 MW of installed capacity) have long-term licenses from FERC. The other plant, with an installed generating capacity of approximately 2 MW, is operated under a permit granted by another federal agency.

Wind: We purchased Montfort Wind Energy Center (Montfort) from NextEra Energy Resources on December 21, 2012 for $27 million. We now have four wind sites, consisting of 200 turbines with an installed capacity of 338 MW and a dependable capability of 67 MW.

Biomass: We are constructing a biomass-fueled power plant at Domtar Corporation's Rothschild, Wisconsin paper mill site. Wood waste and wood shavings will be used to produce approximately 50 MW of renewable electricity and will also support Domtar's sustainable papermaking operations. Construction commenced in June 2011. We currently expect to invest between $245 million and $255 million, excluding Allowance for Funds Used During Construction (AFUDC), in the plant. We are targeting completion of the facility by the end of 2013.

Power Purchase Commitments

We enter into short and long-term power purchase commitments to meet a portion of our anticipated electric energy supply needs. The following table identifies our power purchase commitments as of December 31, 2012 with unaffiliated parties for the next five years:

Year	MW
2013	1,267
2014	1,267
2015	1,267
2016	1,267
2017	1,267

The above commitments include approximately 1,030 MW per year related to the Point Beach long-term power purchase agreement. Under this agreement, we pay a predetermined price per MWh for energy delivered according to a schedule included in the agreement. The balance of these power purchase commitments is a tolling arrangement whereby we are responsible for the procurement, delivery and the cost of natural gas fuel related to a specific unit identified in the contract.

Electric Transmission and Energy Markets

American Transmission Company: ATC is a regional transmission company that owns, maintains, monitors and operates electric transmission systems in Wisconsin, Michigan and Illinois. ATC is expected to provide comparable service to all customers, including Wisconsin Electric, and to support effective competition in energy markets without favoring any market participant. ATC is regulated by FERC for all rate terms and conditions of service and is a transmission-owning member of MISO. MISO maintains operational control of ATC's transmission system, and Wisconsin Electric is a non-transmission owning member and customer of MISO. We owned approximately 26.2% of ATC as of December 31, 2012 and 2011. For additional information, see Note O -- Related Parties in the Notes to Consolidated Financial Statements.

In April 2011, ATC and Duke Energy announced the creation of a joint venture, Duke-American Transmission Company, that will build, own and operate new electric transmission infrastructure in North America to address increasing demand for affordable, reliable transmission capacity.

MISO: In connection with its status as a FERC approved Regional Transmission Organization (RTO), MISO developed bid-based energy markets, which were implemented on April 1, 2005. In January 2009, MISO commenced the Energy and Operating Reserves Markets, which includes the bid-based energy markets and the ancillary services market. For further information on MISO and the MISO Energy Markets, see Factors Affecting Results, Liquidity and Capital Resources -- Industry Restructuring and Competition - Electric Transmission and Energy Markets in Item 7.

Electric Utility Operating Statistics

The following table shows certain electric utility operating statistics for the past five years:

SELECTED CONSOLIDATED ELECTRIC UTILITY OPERATING DATA

Year Ended December 31	2012	2011	2010	2009	2008
Operating Revenues (Millions)					
Residential	$1,163.9	$1,159.2	$1,114.3	$977.6	$962.5
Small Commercial/Industrial	1,013.6	1,006.9	922.2	860.3	869.7
Large Commercial/Industrial	744.3	763.7	677.1	599.4	646.3
Other - Retail	22.8	22.9	21.9	21.2	20.8
Total Retail Revenues	2,944.6	2,952.7	2,735.5	2,458.5	2,499.3
Wholesale - Other	144.4	154.0	134.6	116.7	77.7
Resale - Utilities	53.4	69.5	40.4	47.5	37.7
Other Operating Revenues	51.5	35.1	25.8	62.3	45.9
Total Operating Revenues	$3,193.9	$3,211.3	$2,936.3	$2,685.0	$2,660.6
MWh Sales (Thousands)					
Residential	8,317.7	8,278.5	8,426.3	7,949.3	8,277.1
Small Commercial/Industrial	8,860.0	8,795.8	8,823.3	8,571.6	9,023.7
Large Commercial/Industrial	9,710.7	9,992.2	9,961.5	9,140.3	10,691.7
Other - Retail	154.8	153.6	155.3	156.5	161.5
Total Retail Sales	27,043.2	27,220.1	27,366.4	25,817.7	28,154.0
Wholesale - Other	1,566.6	2,024.8	2,004.6	1,529.4	2,620.7
Resale - Utilities	1,642.4	2,065.7	1,103.8	1,548.9	881.0
Total Sales	30,252.2	31,310.6	30,474.8	28,896.0	31,655.7
Customers - End of Year (Thousands)					
Residential	1,008.2	1,005.5	1,003.6	1,001.2	999.1
Small Commercial/Industrial	114.3	113.8	113.5	113.1	112.6
Large Commercial/Industrial	0.7	0.7	0.7	0.7	0.7
Other	2.5	2.5	2.4	2.4	2.4
Total Customers	1,125.7	1,122.5	1,120.2	1,117.4	1,114.8
Customers - Average (Thousands)	1,123.8	1,121.0	1,118.7	1,115.5	1,111.8
Degree Days (a)					
Heating (6,662 Normal)	5,704	6,633	6,183	6,825	7,073
Cooling (696 Normal)	1,041	793	944	475	593

(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 operating under the trade name of "We Energies." We 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. We also transport customer-owned gas. We are the largest natural gas distribution utility in Wisconsin and we operate throughout the state, including the City of Milwaukee, west and south of the City of Milwaukee, the Appleton area and large areas of both central and western Wisconsin.

Gas Deliveries

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

Total gas therms delivered, including customer-owned transported gas, were approximately 2,222.0 million therms during 2012, a 3.2% increase compared with 2011. As of December 31, 2012, we were transporting gas for approximately 1,600 customers who purchased gas directly from other suppliers. Transported gas accounted for approximately 51.3% of the total volumes delivered during 2012, 41.8% during 2011 and 43.5% during 2010. We had approximately 1,074,000 and 1,068,200 gas customers as of December 31, 2012 and 2011, respectively. Our peak daily send-out during 2012 was 1,583,041 Dth on January 19, 2012.

Sales to Large Gas Customers: We provide gas utility service to a diversified base of industrial customers who are largely within our electric service territory. Major industries served include the paper, food products and fabricated metal products industries. Fuel used for Wisconsin Electric's electric generation represents our largest transportation customer. Gas therms delivered to Wisconsin Electric for electric generation represents 17.2%, 8.3% and 10.3% of the total volumes delivered during 2012, 2011 and 2010, respectively.

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, 2017 as new customer additions are expected to be offset by a reduction in the average use per customer. This forecast reflects a current year weather normalized sales level and normal weather.

Western Gas Lateral: We are projecting the need for additional capacity for our natural gas distribution network in the western part of Wisconsin to address reliability and meet customer demand. We anticipate seeking approval to construct a new natural gas lateral from the PSCW in 2013. The anticipated cost of the initial phase of this project is approximately $150 million to $170 million.

Competition

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

Our ability to maintain our share of the industrial dual-fuel market 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. While the gas utility distribution function is expected to remain a highly regulated, monopoly function, the sale 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.

Pipeline Capacity and Storage: The interstate pipelines serving Wisconsin originate in major gas producing areas of North America: the Oklahoma and Texas basins, the Gulf of Mexico, western Canada and the Rocky Mountains. We have contracted for long-term firm capacity from a number of these sources. This strategy reflects management's belief that overall supply security is enhanced by geographic diversification of the supply portfolio.

Due to the daily and seasonal variations in gas usage in Wisconsin, we have also contracted for substantial underground storage capacity, primarily in Michigan. We target storage levels at approximately 35% of forecasted winter demand. Storage capacity, along with our gas purchase contracts, enables us to manage significant changes in daily demand and to optimize our overall gas supply and capacity costs. We generally inject gas into storage during the spring and summer months when demand is lower and withdraw it in the winter months. As a result, we can contract for less long-line pipeline capacity during periods of peak usage than would otherwise be necessary and can purchase gas on a more uniform daily basis from suppliers year-round. Each of these capabilities enables us to reduce our overall costs.

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 Chicago, Illinois market hub and in the 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 Wisconsin Electric, must contract for capacity and supply sufficient to meet the firm peak-day demand of their customers. Peak or near peak demand days generally occur only a few times each year. Capacity release facilitates higher utilization of contracted capacity and supply during those times when the full contracted capacity and supply are not needed by the utility, helping to mitigate the fixed costs associated with maintaining peak levels of capacity and gas supply. Through pre-arranged agreements and day-to-day electronic bulletin board postings, interested parties can purchase this excess capacity and supply. The proceeds from these transactions are passed through to rate payers, subject to the Wisconsin Electric and Wisconsin Gas approved Gas Cost Recovery Mechanisms (GCRMs). During 2012, we continued to participate in the capacity release market. See Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters in Item 7 for information on the GCRMs.

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 60% of planned winter and (ii) up to 30% planned summer flowing gas supply using a mix of New York Mercantile Exchange (NYMEX) based natural gas options and natural gas future contracts. Those approvals allow both Wisconsin Electric and Wisconsin Gas to pass 100% of the hedging costs (premiums and brokerage fees) and proceeds (gains and losses) to rate payers through their respective GCRMs. Hedge targets (volumes) are provided annually to the PSCW as part of each company's three-year gas supply plan and risk management filing.

To the extent that opportunities develop and physical supply operating plans are supportive, 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 our GCRMs.

Gas Utility Operating Statistics

The following table shows certain gas utility operating statistics for the past five years:
SELECTED CONSOLIDATED GAS UTILITY OPERATING DATA

Year Ended December 31	2012	2011	2010	2009	2008
Operating Revenues (Millions)					
Residential	$612.0	$737.4	$754.2	$856.6	$1,057.6
Commercial/Industrial	289.7	369.9	373.1	442.9	572.4
Interruptible	7.3	9.4	11.8	11.9	21.3
Total Retail Gas Sales	909.0	1,116.7	1,139.1	1,311.4	1,651.3
Transported Gas	49.4	49.2	48.0	44.8	47.2
Other Operating Revenues	4.2	15.3	3.1	11.7	(3.9)
Total Operating Revenues	$962.6	$1,181.2	$1,190.2	$1,367.9	$1,694.6
Therms Delivered (Millions)					
Residential	676.4	776.8	741.2	803.4	841.8
Commercial/Industrial	390.6	461.7	429.6	479.4	503.2
Interruptible	14.6	16.0	19.4	19.1	23.0
Total Retail Gas Sales	1,081.6	1,254.5	1,190.2	1,301.9	1,368.0
Transported Gas	1,140.4	899.6	914.9	882.0	905.8
Total Therms Delivered	2,222.0	2,154.1	2,105.1	2,183.9	2,273.8
Customers - End of Year (Thousands)					
Residential	980.3	975.2	971.7	967.7	963.9
Commercial/Industrial	92.0	91.5	91.3	91.1	91.0
Interruptible	0.1	0.1	0.1	0.1	0.1
Transported Gas	1.6	1.4	1.4	1.3	1.4
Total Customers	1,074.0	1,068.2	1,064.5	1,060.2	1,056.4
Customers - Average (Thousands)	1,068.9	1,064.1	1,060.2	1,055.6	1,050.2
Degree Days (a)					
Heating (6,662 Normal)	5,704	6,633	6,183	6,825	7,073

(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: Our steam utility generates, distributes and sells steam supplied by our VAPP and Milwaukee County Power Plant. We operate a district steam system in downtown Milwaukee and the near south side of Milwaukee. Steam is supplied to this system from VAPP, a coal-fired cogeneration facility. We also operate 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 2012, the steam utility had $34.3 million of operating revenues from the sale of 2,449 million pounds of steam compared with $39.0 million of operating revenues from the sale of 2,733 million pounds of steam during 2011. As of December 31, 2012 and 2011, steam was used by approximately 460 customers and 465 customers, respectively, for processing, space heating, domestic hot water and humidification.

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 consists primarily of generating plants constructed as part of our PTF strategy. As of December 31, 2012, our PTF assets represented virtually all of our non-utility energy segment assets.

We Power

We Power, through wholly owned subsidiaries, has designed and built approximately 2,320 MW of new generation in Wisconsin, which is being leased to Wisconsin Electric under long-term leases. This new generation consists of approximately 1,230 MW of capacity from OC 1 and OC 2, and 1,090 MW of capacity from PWGS 1 and PWGS 2. PWGS 1 and PWGS 2 were placed in service in July 2005 and May 2008, respectively. OC 1 and OC 2 were placed in service in February 2010 and January 2011, respectively. In November 2005, two unaffiliated entities collectively purchased an ownership interest of approximately 17%, or 200 MW, in OC 1 and OC 2. Similar to the generating capacity at PWGS 1 and PWGS 2, We Power owns the remaining generating capacity at OC 1 and OC 2.

Our PTF strategy was designed to address Wisconsin Electric's electric supply needs by increasing the electric generating capacity in Wisconsin while allowing us to maintain a diversified fuel mix, by including both new coal-fired plants and natural-gas fired plants. Because of the significant investment necessary to construct these generating units, we constructed the plants under Wisconsin's Leased Generation Law, which became effective in August 2001 and allows a non-utility affiliate to construct an electric generating facility and lease it to the public utility. The law allows a public utility that has entered into a lease approved by the PSCW to recover fully in its retail electric rates that portion of any payments under the lease that the PSCW has allocated to the public utility's Wisconsin retail electric service, and all other costs that are prudently incurred in the public utility's operation and maintenance of the electric generating facility allocated to the utility's Wisconsin retail electric service. In addition, the PSCW may not modify or terminate a lease it has approved under the Leased Generation Law except as specifically provided in the lease or the PSCW's order approving the lease. This law effectively created regulatory certainty in light of the significant investment being made to construct the units. All four PTF units were constructed under leases approved by the PSCW. For additional background information on our PTF strategy, see Management's Discussion and Analysis of Financial Condition and Results of Operations - Corporate Developments - Corporate Strategy - Power the Future Strategy and - Factors Affecting Results, Liquidity and Capital Resources - Power the Future in Item 7 of our Form 10-K for the year ended December 31, 2007.

For further information about our PTF strategy, see Factors Affecting Results, Liquidity and Capital Resources -- Power the Future in Item 7.

Wisvest LLC

Wisvest was originally formed to develop, own and operate electric generating facilities and to invest in other energy-related entities. As a result of the change in corporate strategy to focus on our PTF strategy, Wisvest discontinued its development activity. As of December 31, 2012, Wisvest's sole operating asset and investment is Wisvest Thermal Energy Services, which provides chilled water services to the Milwaukee Regional Medical Center.

OTHER NON-UTILITY OPERATIONS

Wispark LLC and Bostco LLC

Wispark and Bostco develop and invest in real estate, and combined had $83.4 million in real estate holdings as of December 31, 2012. Wispark has developed several business parks and other commercial real estate projects, primarily in southeastern Wisconsin.

REGULATION

Wisconsin Energy Corporation

Wisconsin Energy is a holding company, but is exempt from the requirements of the Public Utility Holding Company Act of 2005 (PUHCA 2005).

Non-Utility Asset Cap: Pursuant to the non-utility asset cap provisions of Wisconsin's 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 law exempts energy-related assets, including the generating plants constructed by We Power as part of our PTF strategy and assets 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, 2012.

Utility Energy Segment

Wisconsin Electric is a holding company because of its ownership interest in ATC, but is exempt from the requirements of PUHCA 2005.

Wisconsin Electric is subject to the Federal Power Act and the corresponding regulations developed by certain federal agencies. The Energy Policy Act amended the Federal Power Act in 2005 to, among other things, make electric utility industry consolidation more feasible, authorize FERC to review proposed mergers and the acquisition of generation facilities, change the FERC regulatory scheme applicable to qualifying cogeneration facilities and modify certain other aspects of energy regulations and Federal tax policies applicable to Wisconsin Electric. Additionally, the Energy Policy Act created an Electric Reliability Organization to be overseen by FERC, which established mandatory electric reliability standards and which has the authority to levy monetary sanctions for failure to comply with these standards.

Wisconsin Electric and Wisconsin Gas 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, construction of certain new facilities, transactions with affiliates, billing practices and various other matters. Wisconsin Electric is also subject to the regulation of the PSCW as to certain levels of short-term debt obligations. Wisconsin Electric is subject to the regulation of the MPSC as to the various matters associated with retail electric service in the state of Michigan, except as to the issuance of securities in the ordinary course of business, construction of certain new facilities, levels of short-term debt obligations and advance approval of transactions with affiliates in the ordinary course of business. Wisconsin Electric's hydroelectric facilities are regulated by FERC. Wisconsin Electric is subject to the regulation of FERC with respect to wholesale power service, electric reliability requirements and accounting and with respect to our participation in the interstate natural gas pipeline capacity market. For information on how rates are set for our regulated entities, see Utility Rates and Regulatory Matters under Factors Affecting Results, Liquidity and Capital Resources in Item 7.

The following table compares our utility energy segment operating revenues by regulatory jurisdiction for each of the three years in the period ended December 31, 2012:

	2012			2011			2010		
	Amount	Percent		Amount	Percent		Amount	Percent	
	(Millions of Dollars)								
Electric									
Wisconsin - Retail	$2,808.4	87.9	%	$2,775.8	86.4	%	$2,568.3	87.5	%
Michigan - Retail	187.8	5.9	%	212.0	6.6	%	193.0	6.6	%
FERC - Wholesale	197.7	6.2	%	223.5	7.0	%	175.0	5.9	%
Total	3,193.9	100.0	%	3,211.3	100.0	%	2,936.3	100.0	%
Gas - Wisconsin - Retail	962.6	100.0	%	1,181.2	100.0	%	1,190.2	100.0	%
Steam - Wisconsin - Retail	34.3	100.0	%	39.0	100.0	%	38.8	100.0	%
Total Utility Operating Revenues	$4,190.8			$4,431.5			$4,165.3		

The operations of Wisconsin Electric and Wisconsin Gas are also subject to regulations, where applicable, of the United States Environmental Protection Agency (EPA), the Wisconsin Department of Natural Resources (WDNR), the Michigan Department of Environmental Quality and the Michigan Department of Natural Resources.

Public Benefits and Renewable Portfolio Standard

2005 Wisconsin Act 141 (Act 141) established a goal that 10% of electricity consumed in Wisconsin be generated by renewable resources by December 31, 2015. Under Act 141, we must meet certain minimum requirements for renewable energy generation. For the years 2010 through 2014, we must increase our percentage of total retail energy sales provided by renewable sources (renewable energy percentage) by at least two percentage points from our baseline renewable percentage of 2.27% to a level of 4.27%. Act 141 defines "baseline renewable percentage" as the average of an energy provider's renewable energy percentage for 2001, 2002 and 2003. As of December 31, 2012, we are in compliance with the Wisconsin renewable energy percentage of 4.27%. Act 141 further requires that for the year 2015 and beyond, the renewable energy percentage must increase at least six percentage points above the baseline to a level of 8.27%. In addition, under this Act, 1.2% of utilities' annual operating revenues were required to be used to fund energy conservation programs in 2012. The funding required by Act 141 for 2013 is also 1.2% of annual operating revenues.

Public Act 295 enacted in Michigan requires 10% of the state's energy to come from renewables by 2015 and energy optimization (efficiency) targets up to 1% annually by 2015. Public Act 295 specifically calls for current recovery of costs incurred to meet the standards and provides for ongoing review and revision to assure the measures taken are cost-effective.

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 - Renewable Energy Portfolio in Item 7.

Non-Utility Energy Segment

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

Environmental permits necessary for operating the facilities are the responsibility of the operating entity, Wisconsin Electric.

ENVIRONMENTAL COMPLIANCE

Our operations are subject to extensive environmental regulations by state and federal environmental agencies governing air and water quality, hazardous and solid waste management, environmental remediation and management of natural resources. Costs associated with complying with these requirements are significant. Additional future environmental statutes and regulations or revisions to existing laws, including for example, additional regulation of greenhouse gas emissions, coal combustion products, air emissions or wastewater discharges, could significantly increase these environmental compliance costs.

Anticipated expenditures for environmental compliance and remediation issues for the next three years are included in estimated 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 -- Environmental Matters in Item 7. For a discussion of matters related to certain solid waste and coal combustion product landfills, manufactured gas plant sites and air quality, see Note P -- Commitments and Contingencies in the Notes to Consolidated Financial Statements in Item 8.

Compliance with federal, state and local environmental protection requirements resulted in capital expenditures by Wisconsin Electric of approximately $64.1 million in 2012 compared with $120.3 million in 2011. Expenditures incurred during 2012 and 2011 primarily included costs associated with the installation of pollution abatement facilities at Wisconsin Electric's power plants. These expenditures are expected to be approximately $22 million during 2013, reflecting the addition of control equipment for Nitrogen Oxide (NO_x), Sulfur Dioxide (SO_2) and other pollutants needed to comply with various rules promulgated by the EPA and the Consent Decree entered into with the EPA in 2003. Operation, maintenance and depreciation expenses for fly ash removal equipment and other environmental protection systems were approximately $82.6 million and $79.0 million during 2012 and 2011, respectively.

Coal Combustion Product Fills and Landfills

We currently have a program of beneficial utilization for substantially all of our coal combustion products, including fly ash, bottom ash and gypsum, which minimizes the need for disposal in specially-designed landfills. Some early designed and constructed coal combustion product landfills, which we used prior to developing this program, 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 made to define the nature and extent of any release, and work has been performed to address these conditions. In addition, fill areas for coal ash were used prior to the introduction of landfill regulations. Sites currently undergoing review include the following:

Oak Creek Site Landfills: Groundwater impacts identified near the sites, located in the Village of Caledonia and the City of Oak Creek, Wisconsin, prompted Wisconsin Electric to begin investigation in 2009 for the source of impacts found in monitoring wells on the site and surrounding area. Our study indicates that the groundwater impacts may be naturally occurring or are from other sources based on groundwater flow direction and increasing concentrations of elements deeper in the ground. The WDNR began sampling work in 2011 to identify the source of the groundwater impacts and issued its report on January 24, 2013. The WDNR study found that the data was inconclusive as to the source causing the groundwater impacts. We reviewed the WDNR report and provided technical comments on February 18, 2013 further supporting our position that regional ground water impacts are not a result of coal ash management activities at the Oak Creek site.

See Item 3 Legal Proceedings -- Environmental Matters for a discussion of the bluff collapse at our Oak Creek Power Plant.

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: As of December 31, 2012, we had the following number of employees:

	Total Employees	Represented Employees
Utility Energy Segment		
Wisconsin Electric	4,054	2,660
Wisconsin Gas	443	310
Total	4,497	2,970
Non-Utility Energy Segment	3	—
Other	4	—
Total Employees	4,504	2,970

The employees represented under labor agreements were with the following bargaining units as of December 31, 2012:

	Number of Employees	Expiration Date of Current Labor Agreement
Wisconsin Electric		
Local 2150 of International Brotherhood of Electrical Workers	1,829	August 15, 2013
Local 420 of International Union of Operating Engineers	554	March 31, 2013
Local 2006 Unit 5 of United Steel Workers	161	October 31, 2013
Local 510 of International Brotherhood of Electrical Workers	116	April 30, 2013
Total Wisconsin Electric	2,660	
Wisconsin Gas		
Local 2150 of International Brotherhood of Electrical Workers	82	August 15, 2013
Local 2006 Unit 1 of United Steel Workers	222	October 31, 2013
Local 2006 Unit 3 of United Steel Workers	6	February 28, 2013
Total Wisconsin Gas	310	
Total Represented Employees	2,970	

ITEM 1A. RISK FACTORS

Risks Related to the Operation of Our Business

Our business is significantly impacted by governmental regulation.

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

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

We estimate that within our regulated energy segment, approximately 88% of our electric revenues are regulated by the PSCW, 6% are regulated by the MPSC and the balance of our electric revenues is regulated by FERC. All of our natural gas and steam revenues are regulated by the PSCW. Our ability to obtain rate adjustments in the future is dependent upon regulatory action, and there can be no assurance that we will be able to obtain rate adjustments in the future that will allow us to recover our costs and expenses and to maintain our current authorized rates of return.

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

Governmental agencies could modify our permits, authorizations or licenses.

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

Also, if we are unable to obtain, renew or comply with these governmental permits, authorizations or licenses, or if we are unable to recover any increased costs of complying with additional license requirements or any other associated costs in our rates in a timely manner, our results of operations and financial condition could be materially and adversely affected.

Factors beyond our control could adversely affect project costs and completion of construction projects.

We are in the process of constructing new renewable generation, including the biomass facility in Rothschild, Wisconsin. These types of construction projects 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 ability to obtain or the cost of labor or materials; the ability of the contractors to perform under their contracts; strikes; adverse weather conditions; the ability to obtain necessary operating permits in a timely manner; legal challenges; changes in applicable law or regulations; adverse interpretation or enforcement of permit conditions, laws and regulations by courts or the permitting agencies; other governmental actions; and events in the global economy.

If we are unable to complete the development or construction of a facility or decide to delay or cancel construction, we may not be able to recover our investment in the facility and may incur substantial cancellation payments under equipment and construction contracts. Even if a construction project is completed, the total costs may be higher than estimated and/or higher than amounts approved by our regulators, and there is no guarantee that we will be allowed to recover these costs in rates. Construction delays can also result in the delay of revenues and, therefore, could affect our results of operations.

In addition, construction delays at our biomass facility currently under construction could result in the loss of a cash grant we expect to receive pursuant to the National Defense Authorization Act (NDAA). The PSCW included the anticipated proceeds from this grant when it set Wisconsin Electric's retail electric rates in Wisconsin Electric's 2013 rate case, thereby reducing the amounts collected directly from our customers.

We have announced plans to upgrade our electric and natural gas distribution systems. Although these projects are smaller in scope than the above referenced construction projects, they are still subject to many of the same risks and challenges.

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

Our results of operations are affected by customer growth in our service areas. Customer growth and energy use can be affected by population growth as well as economic factors in Wisconsin and the Upper Peninsula of Michigan, including job and income growth. Customer growth directly influences the demand for electricity and gas, and the need for additional power generation and generating facilities. Population declines and/or business closings in our service territories or slower than anticipated customer growth has a negative impact on our results of operations and cash flow and could expose us to greater risks of accounts receivable write-offs if customers are unable to pay their bills.

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.

Severe weather events, such as floods, droughts, tornadoes and blizzards, could result in substantial damage to or limit the operation of our facilities.

Severe weather events could result in substantial damage to our electric generating and gas distribution facilities, as well as ATC's transmission lines. Our hydroelectric generation operations could be adversely affected if there is a significant change in water levels in their respective waterways. In addition, a significant reduction in water levels in waterways that supply cooling water to our coal- and natural gas-fired power plants, whether by drought or otherwise, could restrict or prevent the operation of such facilities.

In the event we experience any of these weather events or other natural disaster, recovery of any costs in excess of any reserves or applicable insurance is subject to the approval of the PSCW and/or MPSC. There is no guarantee that we will be allowed to fully recover any such costs or that cost recovery will not be delayed or otherwise conditioned. Any denial or delay in recovery of any such costs could adversely affect our results of operations and cash flows.

In addition, damages resulting from severe weather events within our service territories may result in the loss of customers and reduced demand for electricity and natural gas for extended periods. Any significant loss of customers or reduction in demand could adversely affect our results of operations and cash flows.

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

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

We are a holding company and rely on the earnings of our subsidiaries to meet our financial obligations.

As a holding company, 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. Prior to distributing cash to Wisconsin Energy, our subsidiaries have financial obligations that must be satisfied, including among others, debt service and preferred stock dividends. Our subsidiaries also have dividend payment restrictions based on the terms of their outstanding preferred stock and regulatory limitations applicable to them. In addition, each of the bank back-up credit facilities for Wisconsin Energy, Wisconsin Electric and Wisconsin Gas have specified total funded debt to capitalization ratios that must be maintained.

An increase in natural gas costs could negatively impact our electric and gas utility operations.

Wisconsin Electric burns natural gas in several of its peaking power plants and in PWGS 1 and PWGS 2, and as a supplemental fuel at several coal-fired plants. In many instances the cost of purchased power is tied to the cost of natural gas. Disruption in the supply of natural gas due to a curtailment in production or distribution can increase the cost of natural gas, as can international market conditions and demand for natural gas. Higher natural gas costs can have the effect of increasing demand for other sources of fuel thereby increasing the costs of those fuels as well. Additionally, high natural gas costs increase our working capital requirements.

For Wisconsin customers, Wisconsin Electric bears the risk for the recovery of fuel and purchased power costs within a symmetrical two percent fuel tolerance band compared to the forecast of fuel and purchased power costs established in its rate structure. Our gas distribution business receives dollar for dollar recovery of the cost of natural gas, subject to tolerance bands and prudency review.

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

We are dependent on coal for much of our electric generating capacity. Although we currently have an adequate supply of coal at our coal-fired facilities, there can be no assurance that we will continue to have an adequate supply of coal in the future. While we have coal supply and transportation contracts in place, there can be no assurance that the counterparties to these agreements will be able to 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. Furthermore, international demand for coal can impact its availability and cost. If we significantly reduce our inventory of coal and 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 reduce generation at our coal units and replace this lost generation through additional power purchases in the

MISO Energy Markets.

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

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

We could be the subject of cyber intrusions that disrupt our electric generation and gas distribution operations and/or result in security breaches that expose us to a risk of loss or misuse of confidential and proprietary information, litigation and potential liability.

We operate in an industry that requires the continued operation of sophisticated information technology systems and network infrastructure, which are part of an interconnected regional transmission grid. In addition, in the ordinary course of business, we collect and retain sensitive information including personal information about our customers and employees.

Cyber intrusions, including those targeting the electronic control systems used at our generating facilities and for the electric and gas distribution systems, could result in a full or partial disruption of our electric generation and/or gas distribution operations. Any disruption of these operations could result in a loss of service to customers and a significant decrease in revenues, as well as significant expense to repair system damage and remedy security breaches. Furthermore, we may need to obtain more expensive purchased power to meet customer demand for electricity if our electric generating facilities are unable to operate at full capacity as a result of a cyber intrusion. Any resulting loss of revenue or increase in expense could have a material adverse effect on our results of operations, cash flow and financial condition.

In addition, any theft, loss and/or fraudulent use of customer, stockholder, employee or proprietary data as a result of cyber intrusion or otherwise could subject us to significant litigation, liability and costs, as well as adversely impact our reputation with customers, stockholders and regulators, among others.

Internet-based attacks on critical U.S. energy infrastructure are occurring with more frequency. On February 12, 2013, the President issued an Executive Order providing for intelligence gathering and information exchange on cyber attacks and cyber threats to privately owned critical infrastructure. The framework is to be developed jointly by the government and industry. As cyber attacks become more sophisticated generally and/or as this framework is implemented, we may be required to incur significant costs to strengthen our information and electronic control systems from outside intrusions and/or to obtain insurance coverage related to the threat of such attacks.

Wisconsin Electric could be subject to higher costs and penalties as a result of mandatory reliability standards.

Wisconsin Electric is subject to mandatory reliability and critical infrastructure protection standards established by the North American Electric Reliability Corporation. The critical infrastructure protection standards focus on controlling access to critical and physical and cybersecurity assets. Compliance with the mandatory reliability standards could subject Wisconsin Electric to higher operating costs. If Wisconsin Electric is found to be in noncompliance with the mandatory reliability standards, it could be subject to sanctions, including substantial monetary penalties.

A downgrade in the credit ratings of WEC or any of its subsidiaries could negatively affect their ability to access capital at reasonable costs and/or require the posting of collateral.

There are a number of factors that impact Wisconsin Energy's and its subsidiaries' credit ratings, including, without limitation, capital structure, regulatory environment, the ability to cover liquidity requirements, and other requirements for capital. Wisconsin Energy or any of its subsidiaries could experience a downgrade in their ratings if the rating agencies determine that the level of business or financial risk of the industry or Wisconsin Energy and/or its subsidiaries has deteriorated. Changes in rating methodologies by the rating agencies could also have a negative impact on credit ratings. If Wisconsin Energy or its subsidiaries are downgraded by the rating agencies, their borrowing costs could increase, funding sources could decrease and, for any downgrade to below investment grade, collateral requirements may be triggered in several contracts.

Failure to attract and retain an appropriately qualified workforce could adversely impact our results of operations.

We operate in an industry that requires many of our employees to possess a unique technical skill set. Events such as an aging workforce without appropriate replacements may lead to operating challenges or increased costs. These operating challenges include lack of resources, loss of knowledge and a lengthy time period associated with skill development. Failure to hire and obtain replacement employees, including the ability to transfer significant internal historical knowledge and expertise to the new employees, may adversely affect our ability to manage and operate our business. If we are unable to successfully attract and retain an appropriately qualified workforce, our results of operations could be adversely affected.

Work stoppages or increased labor costs could adversely affect our operations and financial condition.

As of December 31, 2012, we had 4,504 total employees, of which 2,970 or approximately 66% are represented by labor unions. All of our labor agreements are scheduled to expire in 2013. We expect that rising healthcare, pension and wage costs, among other things, will be important topics for negotiation. It is important for us to control healthcare, pension and wage costs provided for in the labor agreements, or we risk increased operational costs. If we are unable to negotiate acceptable contracts with these unions, we could be subject to strikes, work stoppages or other slowdowns by the affected workers. These actions could disrupt our operations and have an adverse effect on our financial condition and results of operations.

The use of derivative contracts could result in financial losses.

We use derivative instruments such as swaps, options, futures and forwards to manage commodity exposures. We could recognize financial losses as a result of volatility in the market value of these contracts or if a counterparty fails to perform. These risks are managed through risk management policies, which might not work as planned and cannot entirely eliminate the risks associated with these activities. In addition, although the hedging programs of Wisconsin Electric and Wisconsin Gas must be approved by the PSCW, derivative contracts entered into for hedging purposes might not offset the underlying exposure being hedged as expected, resulting in financial losses. In the absence of actively quoted market prices and pricing information from external sources, the value of these financial instruments can involve management's judgment or use of estimates. Changes in the underlying assumptions or use of alternative valuation methods could affect the value of the reported fair value of these contracts.

The Dodd-Frank Act, enacted in July 2010, provides for the regulation of derivatives and grants the CFTC expanded regulatory authority over derivative and swap transactions. The CFTC has promulgated numerous regulations that will impose additional requirements on the use of derivatives and swap transactions for us and our counterparties, which could affect both the use and cost of these instruments. Several of the rules still need to be finalized, pending the CFTC's requests for further comments on certain interim rules, interpretations and proposed exemptions, and requests for clarifications by several interested parties. Although we cannot be certain of the impact of these new rules on us until these matters are fully resolved, we currently do not expect it to be material.

Our revenues could be negatively impacted by competitive activity in the wholesale electricity markets.

FERC rules related to transmission are designed to facilitate competition in the wholesale electricity markets among regulated utilities, non-utility generators, wholesale power marketers and brokers by providing greater flexibility and more choices to wholesale customers, including initiatives designed to encourage the integration of renewable sources of supply. In addition, along with transactions contemplating physical delivery of energy, financial laws and regulations impact hedging and trading based on futures contracts and derivatives that are traded on various commodities exchanges, as well as over-the-counter (OTC). Technology changes in the power and fuel industries also have significant impacts on wholesale transactions and related costs. We currently cannot predict the impact of these and other developments or the effect of changes in levels of wholesale supply and demand, which are driven by factors beyond our control.

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 whether retail access might be implemented in Wisconsin. Michigan has adopted retail choice which allows customers to remain with their regulated utility at regulated rates or choose an alternative electric supplier to provide power supply service. We continue providing distribution and customer service functions regardless of the customer's power supplier. Although competition and customer switching to alternative suppliers in our service territories in Michigan has been limited, the additional competitive pressures resulting from retail access could lead to a loss of customers and our incurring stranded costs. A loss of customers could also have a material adverse effect on our results of operations and cash flows.

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 bid-based energy markets that are part of the MISO Energy Markets. The MISO Energy Markets rules require that all market participants submit day-ahead and/or real-time bids and offers for energy at locations across the MISO region. MISO then calculates the most efficient solution for all of the bids and offers made into the market that day and establishes a Locational Marginal Price (LMP) that reflects the market price for energy. As a participant in the MISO Energy Markets, we are required to follow MISO's instructions when dispatching generating units to support MISO's responsibility for maintaining stability of the transmission system. MISO also implemented an Ancillary Services Market for operating reserves that was simultaneously co-optimized with its existing energy markets.

These market designs have the potential to increase the costs of transmission, the costs associated with inefficient generation dispatching, the costs of participation in the market and the costs associated with estimated payment settlements.

Risks Related to Legislation and Regulation

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

Our operations are subject to extensive environmental legislation and regulation by state and federal environmental agencies governing, among other things, air emissions such as Carbon Dioxide (CO_2), SO_2, NO_x, fine particulates and mercury; water discharges; and management of hazardous, toxic and solid wastes and substances. 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. In April 2003, Wisconsin Electric reached a Consent Decree with the EPA to significantly reduce air emissions from its coal-fired generating facilities. Through the end of 2012, we had invested approximately $1.2 billion to comply with the Consent Decree. We estimate we will spend an additional $22 million in 2013 for final implementation costs.

We will be required to be in compliance with environmental regulations that become effective over the next several years, including the EPA's Mercury and Air Toxics Standards (MATS) rule, new SO_2 and Nitrogen Dioxide National Ambient Air Quality Standards and new emission limits on fine particulate matter ($PM_{2.5}$), as well as rules related to cooling water intake structures at our power plants. In addition, the EPA adopted the Cross-State Air Pollution Rule (CSAPR), which provides for limits on the interstate transport of NO_x and SO_2 emissions. The U.S. Court of Appeals for the D.C. Circuit vacated the CSAPR. The EPA had requested the Court to re-hear the case; however, on January 24, 2013 the court denied the EPA's request. The EPA may still appeal this decision to the United States Supreme Court. Therefore, there is still substantial uncertainty as to what capital expenditures may ultimately be required to comply with these regulations. In the meantime, the Clean Air Interstate Rule (CAIR) remains in effect.

We continue to assess the potential cost of complying, and to explore different alternatives in order to comply, with these and other environmental regulations. We entered a joint ownership agreement with Wolverine regarding PIPP whereby, subject to the approval of various state and federal agencies, Wolverine will pay for the installation of environmental upgrades at the plant and will receive a minority ownership interest in the plant in return. In addition, we announced plans to convert the fuel source for VAPP from coal to natural gas at an expected cost of between $60 million and $65 million. These and other compliance costs we expect to incur over the next three years are included in the table under "Capital Expenditures" in the Liquidity and Capital Resources section of Management's Discussion and Analysis of Financial Condition and Results of Operations.

Existing environmental regulations may be revised or new laws or regulations may be adopted at the federal or state level which could result in significant additional expenditures, operating restrictions on our facilities and increased compliance costs. In addition, the operation of emission control equipment 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. Additional environmental legislation and regulation and the related compliance costs could affect future unit retirement and replacement decisions.

If we fail to comply with environmental laws and regulations, even if caused by factors beyond our control, that failure may result in the assessment of civil or criminal penalties and fines. The Wisconsin Department of Natural Resources (WDNR) has issued notices of violation to Wisconsin Electric alleging violations of certain environmental rules. An adverse outcome in these matters could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties.

In the event we are not able to recover all of our environmental expenditures and related costs from our customers in the future, our results of operations and financial condition 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 certain of our current and former facilities, and 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.

We may also be subject to potential liability in connection 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 (or failed) to comply with environmental laws and regulations or cause (or caused) harm to the environment or persons, that failure or harm may result in the assessment of civil penalties and damages against us. The incurrence of a material environmental liability or a material judgment in any action for personal injury or property damage related to environmental matters could have a significant adverse effect on our results of operations and financial condition.

Energy conservation and rate increases could negatively impact financial results.

Wisconsin and Michigan have adopted energy efficiency targets to reduce energy consumption by certain dates. To the extent there is any regulatory lag to adjust rates as a result of reduced sales from effective conservation measures, these measures could have a negative impact on our results of operations and cash flows.

In addition, any higher costs that are collected through rates could contribute to reduced demand for electricity, natural gas or steam, which could adversely impact our results of operations and financial condition.

We may face significant costs if coal combustion products are regulated as hazardous waste.

We currently have a program of beneficial utilization for substantially all of our coal combustion products, including fly ash, bottom ash and gypsum, which minimizes the need for disposal in specially-designed landfills. Both Wisconsin and Michigan have regulations governing the use and disposal of these materials. In 2010, the EPA issued draft rules for public comment proposing two alternative rules for regulating coal combustion products, one of which would classify the materials as hazardous waste. If coal combustion products are classified as hazardous waste, it could have a material adverse effect on our ability to continue our current program.

If coal combustion products are classified as hazardous waste and we terminate our coal combustion products utilization program, we could be required to dispose of the coal combustion products at a significant cost to the Company, which could adversely impact our results of operations and financial condition. We anticipate that the earliest the EPA will take action on this matter is the first quarter of 2014.

In addition, the EPA finalized the Commercial and Industrial Solid Waste Incineration Units rule under the Clean Air Act (CAA), and finalized a Non-Hazardous Secondary Materials Rule. Both of these rules have the potential to negatively affect our ability to reburn coal ash from power plants and landfills.

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

The President's administration recently reaffirmed that the regulation of greenhouse gas emissions continues to be a top priority. Legislation that would impose mandatory requirements related to greenhouse gas emissions, renewable energy standards and/or energy efficiency standards has failed to pass in the U.S. Congress; however, we expect such legislation to be considered in the future. Although we cannot currently predict with any certainty what form these future regulations will take, the stringency of the regulations or when they will become effective, we do believe that future governmental legislation and/or regulation may require us to limit or control greenhouse gas emissions from our operations, purchase allowances for such emissions or otherwise incur costs in connection with such emissions.

While climate legislation has yet to be adopted, the EPA is pursuing regulation of greenhouse gas emissions using its existing authority under the CAA. In March 2010, the EPA issued regulations governing the applicability of the CAA's permitting requirements for greenhouse gas emissions to power plants and other commercial and industrial facilities. These rules became applicable to sources that are already subject to CAA permitting requirements, as well as new and modified sources, during 2011. In March 2012, the EPA proposed new source performance standards pertaining to greenhouse gas emissions from certain new power plants, including coal-fired plants, based on the performance of combined cycle natural gas-fueled generating plants. We believe this rule effectively prohibits new conventional coal-fired power plants. In June 2012, the U.S. Court of Appeals for the D.C. Circuit upheld the EPA's authority to regulate greenhouse gas emissions. We expect the EPA to attempt to address performance standards for existing generating units in 2013. Any such regulations may impact how we operate our existing facilities.

Legislation to regulate greenhouse gas emissions and establish renewable and efficiency standards has also been considered on the state level. Both Wisconsin and Michigan have adopted renewable portfolio standards and energy optimization (efficiency) targets.

Despite the United States Supreme Court's decision in Connecticut v. American Electric Power Co., where the Court ruled that the plaintiffs in that litigation did not have standing to claim nuisance due to the release of greenhouse gas into the atmosphere by the defendants, states and environmental groups have lawsuits pending against electric utilities and others to force reductions in greenhouse gas emissions based upon their contribution to the alleged public nuisance of climate change.

There is no guarantee that we will be allowed to fully recover costs incurred to comply with any future legislation, regulation or order that requires a reduction in greenhouse gas emissions or that cost recovery will not be delayed or otherwise conditioned. Any future legislation or regulation that may be adopted, either at the federal or state level, designed to reduce greenhouse gas emissions could have a material adverse impact on our electric generation and natural gas distribution operations. Such regulation could make some of our electric generating units uneconomic to maintain or operate, and could adversely affect our future results of operations, cash flows and possibly financial condition if such costs are not recovered through regulated rates.

We continue to monitor the legislative, regulatory and legal developments in this area.

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 Act, 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 the system.

In addition, the 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 the Act may delay or reduce the likelihood of a sale or change of control of Wisconsin Energy. As a result, stockholders may be deprived of opportunities to sell some or all of their shares of our common stock at prices that represent a premium over market prices.

Risks Related to Economic and Market Volatility

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, to the extent not satisfied by the cash flow generated by our operations. We have historically secured funds from a variety of sources, including the issuance of short-term and long-term debt securities. Successful implementation of our long-term business strategies, including capital investment, is dependent upon our ability to access the capital markets, including the banking and commercial paper markets, under competitive terms and rates. In addition, we rely on committed bank credit agreements as back-up liquidity which allows us to access the low cost commercial paper markets. If our access to any of these markets were limited, or our cost of capital significantly increased, due to a rating downgrade, an economic downturn or uncertainty, prevailing market conditions, concerns over foreign economic conditions and/or the ability of foreign governments and central banks to respond to changing economic conditions, a negative view of the utility industry, failures of financial institutions or other factors, our ability to implement our business plan could be limited which could materially and adversely affect our results of operations.

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

Our electric and gas utility businesses are impacted by economic cycles and the competitiveness of the commercial and industrial customers we serve. Any economic downturn or disruption of national or international financial markets could adversely affect the financial condition of our customers and demand for their products. Adverse economic conditions in our service territories and/or decreased demand for products produced in our service area could cause a reduction in demand for electricity and/or natural gas that could result in decreased earnings and cash flow. We would also expect our collections of accounts receivable to be adversely impacted.

Our service territories have been impacted by the slow economy the country has been experiencing over the past several years. As a result, we continue to experience electric and natural gas sales below historical trends.

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

Our cost of providing pension and other post-retirement benefit plans is dependent upon a number of factors including actual plan experience and assumptions concerning the future, such as earnings on plan assets, discount rates, the level of interest rates used to measure the required minimum funding levels of the plans, future government regulation and our required or voluntary contributions to be made to the plans. Plan assets are subject to market fluctuations and may yield returns that fall below projected return rates. A decline in the market value of these assets as experienced in prior periods may increase our funding requirements. Changes in interest rates affect plan liabilities - as rates decrease, the liabilities increase, which could increase our funding requirements. Changes in demographics, such as an increase in the number of retirements or changes in life expectancy assumptions, may also increase our funding requirements. Changes made to the plans may also impact current and future pension costs. We are facing rising medical costs for both active and retired employees. It is possible that these costs may increase at a rate that is significantly higher than anticipated. If we are unable to successfully manage our benefit plan assets and medical costs, our cash flows, financial condition or results of operations could be adversely impacted.

Our ability to obtain insurance and the terms of any available insurance coverage could be adversely affected by international, national, state or local events and company-specific events, as well as the financial condition of insurers. Our insurance coverage may not provide protection against all significant losses.

Our ability to obtain insurance, as well as the cost and coverage of such insurance, could be affected by developments affecting our business, as well as by international, national, state or local events, as well as the financial condition of insurers. Insurance coverage may not continue to be available at all or at rates or terms similar to those presently available to us. A loss for which we are not fully insured could have a material adverse effect on our results of operations. In addition, our insurance may not be sufficient or effective under all circumstances and against all hazards or liabilities to which we may be subject. Any losses not covered by insurance could adversely affect our results of operations, cash flows or financial condition.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

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

As of December 31, 2012, we owned the following generating stations:

Name	Fuel	No. of Generating Units	Dependable Capability In MW (a)
Coal-Fired Plants			
South Oak Creek	Coal	4	976
Oak Creek Expansion	Coal	2	1,057
Presque Isle	Coal	5	344
Pleasant Prairie	Coal	2	1,188
Valley	Coal	2	256
Milwaukee County	Coal	3	7
Total Coal-Fired Plants		18	3,828
Hydro Plants (13 in number)		33	40
Port Washington Generating Station	Gas	2	1,090
Germantown Combustion Turbines	Gas/Oil	5	258
Concord Combustion Turbines	Gas/Oil	4	352
Paris Combustion Turbines	Gas/Oil	4	352
Other Combustion Turbines & Diesel	Gas/Oil	2	—
Byron Wind Turbines	Wind	2	—
Blue Sky Green Field	Wind	88	29
Glacier Hills	Wind	90	32
Montfort Wind Energy Center	Wind	20	6
Total System		268	5,987

(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 are established by tests and may change slightly from year to year.

As of December 31, 2012, we operated approximately 21,551 pole-miles of overhead distribution lines and 23,912 miles of underground distribution cable, as well as approximately 350 distribution substations and 289,826 line transformers.

As of December 31, 2012, our gas distribution system included approximately 20,533 miles of distribution and transmission mains connected at 185 gate stations to the pipeline transmission systems of ANR Pipeline Company, Guardian Pipeline L.L.C., Natural Gas Pipeline Company of America, Northern Natural Pipeline Company, Great Lakes Transmission Company, Viking Gas Transmission and Michigan Consolidated Gas Company. We have liquefied natural gas storage plants which convert and store, in liquefied form, natural gas received during periods of low consumption. The liquefied natural gas storage plants have a send-out capability of 73,600 Dth per day. We also have propane air systems for peaking purposes. These propane air systems will provide approximately 2,960 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 we serve. Where distribution lines and services and gas distribution mains and services occupy private property, we have in some, but not all instances, obtained consents, permits or easements for these installations from the apparent owners or those in possession of those properties, generally without an examination of ownership records or title.

As of December 31, 2012, the combined steam systems supplied by the VAPP and Milwaukee County Power Plant consisted of approximately 43 miles of both high pressure and low pressure steam piping, nine miles of walkable tunnels and other pressure regulating equipment.

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 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 our existing facilities are in material compliance with applicable environmental requirements.

Bluff Collapse: On October 31, 2011, a portion of the bluff at our Oak Creek Power Plant collapsed. The affected area, located south of the new Air Quality Control System (AQCS), was a former ravine that had been filled with coal ash prior to the advent of landfill regulations. Following the receipt of permits and approvals from the WDNR, bluff reconstruction and stabilization were completed in November 2012. We received final spill closure related to our rework of the storm water management infrastructure from the WDNR on December 10, 2012, following submission of environmental studies and reports. In addition, the EPA issued its final incident situation report on November 29, 2012. The final construction documentation report was submitted to the WDNR on December 21, 2012.

In March 2012, the WDNR issued a Notice of Violation (NOV) along with its investigative findings. The NOV involved the north surface water detention basin and a related permit condition. A June 2012 letter from the WDNR rescinded the March 2012 NOV, but alleged non-compliance with certain environmental regulations. In late July 2012, the WDNR referred the matter to the Wisconsin Department of Justice (DOJ) for alleged violations of storm water and solid waste statutes and rules. We anticipate the DOJ will seek fines or penalties from us as a result of this incident.

In addition, in November 2011, the Sierra Club provided a Notice of Intent to file a citizens suit under the CAA and Resource Conservation and Recovery Act for alleged violations related to this incident. We have responded that we do not believe there is any basis for a citizen suit. To date, the Sierra Club has not indicated whether they intend to file suit.

Paris Generating Station: See Factors Affecting Results, Liquidity and Capital Resources -- Other Matters for information concerning a NOV issued in connection with the replacement of certain turbine blades as part of maintenance performed on Units 1 and 4 at our Paris Generating Station (PSGS).

Solvay Coke and Gas Site: Wisconsin Electric and Wisconsin Gas have been identified as potentially responsible parties at the Solvay Coke and Gas Site located in Milwaukee, Wisconsin. 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. In 2007, Wisconsin Electric, Wisconsin Gas and several other parties entered into an Administrative Settlement Agreement and Order with the EPA to perform additional investigation and assessment and reimburse the EPA's oversight costs.

In-field investigation activities have commenced. Under the Administrative Settlement Agreement, neither Wisconsin Electric nor Wisconsin Gas admits to any liability for the site, waives any liability defenses, or commits to perform future site remedial activities. The companies' share of the costs to perform the required work 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 P -- Commitments and Contingencies in the Notes to Consolidated Financial Statements in Item 8.

Edgewater Generating Unit 5: In December 2009, the EPA issued a NOV concerning several coal-fired power plants owned and operated by WPL, including Edgewater Generating Unit 5, of which Wisconsin Electric owned 25%. Due to its ownership interest at the time, Wisconsin Electric was named in the NOV. In March 2011, Wisconsin Electric sold its interest to WPL. Although Wisconsin Electric sold its interest, it retained its share of liability, if any, related to the NOV. The NOV alleges that certain maintenance projects at WPL's units, including Edgewater 5, were undertaken without obtaining air permits required by the CAA. Wisconsin Electric, WPL and the co-owners of the other plants identified in the NOV are discussing resolution of this NOV with the EPA. At this time, we cannot predict the outcome of this matter.

In September 2010, the Sierra Club filed a complaint against WPL generally alleging air permitting and opacity violations at the Edgewater Generating Station. Wisconsin Electric is not a named party to this litigation. WPL, the other co-owner of the Edgewater Generating Station, and Wisconsin Electric as a former co-owner, are discussing resolution of this matter with the Sierra Club. At this time, we cannot predict the outcome of this matter.

See Environmental Compliance in Item 1 and Environmental Matters, Manufactured Gas Plant Sites, Coal Combustion Product Landfill Sites and EPA - Consent Decree in Note P -- 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 combustion product landfills, manufactured gas plant sites and air quality.

UTILITY RATE MATTERS

See Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters in Item 7 for information concerning rate matters in the jurisdictions where Wisconsin Electric and Wisconsin Gas 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 United States Department of Energy's (DOE) breach of contract with Wisconsin Electric that required the DOE to begin permanently removing used nuclear fuel from Point Beach by January 31, 1998.

Cash Balance Pension Plan: See Note P -- Commitments and Contingencies in the Notes to Consolidated Financial Statements for information regarding a lawsuit filed against the Wisconsin Energy Corporation Retirement Account Plan (Plan).

For information concerning our PTF strategy, including the Settlement Agreement with Bechtel Power Corporation (Bechtel), see Factors Affecting Results, Liquidity and Capital Resources -- Power the Future.

ITEM 4. MINE SAFETY DISCLOSURES

Not Applicable.

EXECUTIVE OFFICERS OF THE REGISTRANT

The names, ages at December 31, 2012 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.

Gale E. Klappa. Age 62.
- Wisconsin Energy -- Chairman of the Board and Chief Executive Officer since May 2004. President since April 2003.
- Wisconsin Electric -- Chairman of the Board since May 2004. President and Chief Executive Officer since August 2003.
- Wisconsin Gas -- Chairman of the Board since May 2004. President and Chief Executive Officer since August 2003.
- Director of Joy Global, Inc. and Badger Meter, Inc.
- Director of Wisconsin Energy, Wisconsin Electric and Wisconsin Gas since 2003.

Stephen P. Dickson. Age 52.
- Wisconsin Energy -- Vice President since 2005. Controller since 2000.
- Wisconsin Electric -- Vice President since 2005. Controller since 2000.
- Wisconsin Gas -- Vice President since 2005. Controller since 1998.

J. Kevin Fletcher. Age 54.
- Wisconsin Electric -- Senior Vice President since October 2011.
- Wisconsin Gas -- Senior Vice President since October 2011.
- Georgia Power -- Vice President - Community and Economic Development from 2007 to October 2011. Georgia Power is an affiliate of The Southern Company, a public utility holding company serving the southeastern United States.

Robert M. Garvin. Age 46.
- Wisconsin Energy -- Senior Vice President since April 2011.
- Wisconsin Electric -- Senior Vice President since April 2011.
- Wisconsin Gas -- Senior Vice President since April 2011.
- American Transmission Co. -- Vice President and General Counsel from 2009 to April 2011.
- NextEra Energy Resources -- Vice President from 2007 to 2009.

J. Patrick Keyes. Age 47.
- Wisconsin Energy -- Executive Vice President and Chief Financial Officer since September 2012. Treasurer from April 2011 to February 2013. Vice President from April 2011 to August 2012.
- Wisconsin Electric -- Executive Vice President and Chief Financial Officer since September 2012. Treasurer from April 2011 to February 2013. Vice President from April 2011 to August 2012.
- Wisconsin Gas -- Executive Vice President and Chief Financial Officer since September 2012. Treasurer from April 2011 to February 2013. Vice President from April 2011 to August 2012.
- Accenture -- Senior Executive from September 2000 to March 2011.

Frederick D. Kuester. Age 62.
- Wisconsin Energy -- Executive Vice President from May 2004 to January 4, 2013. Chief Financial Officer from March 2011 to August 2012.
- Wisconsin Electric -- Executive Vice President from May 2004 to January 4, 2013. Chief Operating Officer from October 2003 until February 2011. Chief Financial Officer from March 2011 to August 2012.
-

Wisconsin Gas -- Executive Vice President from May 2004 to January 4, 2013. Chief Financial Officer from March 2011 to August 2012.

Mr. Kuester retired effective January 4, 2013.

Mirant Corporation, of which Mr. Kuester was Senior Vice President - International from 2001 to October 2003 and Chief Executive Officer of Mirant Asia - Pacific Limited from 1999 to October 2003, and certain of its subsidiaries voluntarily filed for bankruptcy in July 2003. Other than certain Canadian subsidiaries, none of Mirant's international subsidiaries filed for bankruptcy.

Allen L. Leverett. Age 46.

- Wisconsin Energy -- Executive Vice President since May 2004. Chief Financial Officer from July 2003 to February 2011.
- Wisconsin Electric -- Executive Vice President since May 2004. Chief Financial Officer from July 2003 to February 2011.
- Wisconsin Gas -- Executive Vice President since May 2004. Chief Financial Officer from July 2003 to February 2011.

Susan H. Martin. Age 60.

- Wisconsin Energy -- Executive Vice President and General Counsel since March 2012. Corporate Secretary since December 2007. Vice President and Associate General Counsel from December 2007 to February 2012.
- Wisconsin Electric -- Executive Vice President and General Counsel since March 2012. Corporate Secretary since December 2007. Vice President and Associate General Counsel from December 2007 to February 2012.
- Wisconsin Gas -- Executive Vice President and General Counsel since March 2012. Corporate Secretary since December 2007. Vice President and Associate General Counsel from December 2007 to February 2012.

Kristine A. Rappé. Age 56.

- Wisconsin Energy -- Senior Vice President and Chief Administrative Officer since May 2004.
- Wisconsin Electric -- Senior Vice President and Chief Administrative Officer since May 2004.
- Wisconsin Gas -- Senior Vice President and Chief Administrative Officer since May 2004.

Ms. Rappé is concluding her employment effective February 28, 2013.

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, 2012, based upon the number of Wisconsin Energy Corporation stockholder accounts (including accounts in our dividend reinvestment and stock purchase plan), we had approximately 41,300 registered stockholders.

COMMON STOCK LISTING AND TRADING

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

DIVIDENDS AND COMMON STOCK PRICES

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

On January 17, 2013, our Board of Directors affirmed our dividend policy that targets a dividend payout ratio of 60% in the year 2014, and approved a new dividend policy that targets a payout ratio that trends to 65-70% in 2017. In accordance with that policy, on January 17, 2013, our Board of Directors increased our quarterly dividend to $0.34 per share effective with the first quarter 2013 dividend payment, which would result in annual dividends of $1.36 per share.

Range of Wisconsin Energy Common Stock Prices and Dividends:

	2012			2011		
Quarter	High	Low	Dividend	High	Low	Dividend
First	$35.35	$33.62	$0.30	$31.01	$28.83	$0.26
Second	$40.00	$34.54	0.30	$31.89	$29.39	0.26
Third	$41.48	$37.46	0.30	$32.49	$27.00	0.26
Fourth	$38.93	$36.01	0.30	$35.38	$29.82	0.26
Annual	$41.48	$33.62	$1.20	$35.38	$27.00	$1.04

ISSUER PURCHASES OF EQUITY SECURITIES

2012	Total Number of Shares Purchased (a)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (b)	Maximum Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (Millions of Dollars)
October 1 - October 31	16,578	$37.61	14,000	$185.5
November 1 - November 30	1,013,626	$36.77	1,013,626	$148.3
December 1 - December 31	—	$—	—	$148.3
Total	1,030,204	$36.78	1,027,626	

(a) Of the shares reported during October 2012, 2,578 shares were surrendered by employees to satisfy tax withholding obligations upon vesting of restricted stock.

(b) On May 5, 2011, Wisconsin Energy's Board of Directors authorized a share repurchase program for up to $300 million of our common stock through December 31, 2013.

ITEM 6. SELECTED FINANCIAL DATA
WISCONSIN ENERGY CORPORATION
CONSOLIDATED SELECTED FINANCIAL AND STATISTICAL DATA

Financial	2012	2011	2010	2009	2008
Year Ended December 31					
Net income - Continuing Operations (Millions)	$546.3	$512.8	$454.4	$375.7	$355.1
Earnings per share - Continuing Operations					
Basic	$2.37	$2.20	$1.94	$1.61	$1.52
Diluted	$2.35	$2.18	$1.92	$1.59	$1.50
Dividends per share of common stock	$1.20	$1.04	$0.80	$0.675	$0.54
Operating revenues (Millions)					
Utility energy	$4,190.8	$4,431.5	$4,165.3	$4,092.0	$4,395.5
Non-utility energy	439.9	435.1	320.2	163.1	126.2
Eliminations and Other	(384.3)	(380.2)	(283.0)	(154.2)	(119.3)
Total operating revenues	$4,246.4	$4,486.4	$4,202.5	$4,100.9	$4,402.4
As of December 31 (Millions)					
Total assets	$14,285.0	$13,862.1	$13,059.8	$12,697.9	$12,617.8
Long-term debt (including current maturities) and capital lease obligations	$4,865.9	$4,646.9	$4,405.4	$4,171.5	$4,136.5
Common Stock Closing Price	$36.85	$34.96	$29.43	$24.92	$20.99

CONSOLIDATED SELECTED QUARTERLY FINANCIAL DATA (Unaudited)

	(Millions of Dollars, Except Per Share Amounts) (a)			
	March		June	
Three Months Ended	2012	2011	2012	2011
Operating revenues	$1,191.2	$1,328.7	$944.7	$991.7
Operating income	295.7	295.6	222.6	174.4
Income from Continuing Operations	172.1	170.9	119.3	98.0
Income from Discontinued Operations	—	—	—	11.5
Total Net Income	$172.1	$170.9	$119.3	$109.5
Earnings per share of common stock (basic) (b)				
Continuing operations	$0.75	$0.73	$0.52	$0.42
Discontinued operations	—	—	—	0.05
Total earnings per share (basic)	$0.75	$0.73	$0.52	$0.47
Earnings per share of common stock (diluted) (b)				
Continuing operations	$0.74	$0.72	$0.51	$0.41
Discontinued operations	—	—	—	0.05
Total earnings per share (diluted)	$0.74	$0.72	$0.51	$0.46

	September		December	
Three Months Ended	2012	2011	2012	2011

Operating revenues	$1,039.3	$1,052.8	$1,071.2	$1,113.2
Operating income	280.6	224.3	201.4	193.0
Income from Continuing Operations	156.1	129.8	98.8	114.1
Income from Discontinued Operations	—	—	—	1.9
Total Net Income	$156.1	$129.8	$98.8	$116.0
Earnings per share of common stock (basic) (b)				
Continuing operations	$0.68	$0.56	$0.43	$0.49
Discontinued operations	—	—	—	0.01
Total earnings per share (basic)	$0.68	$0.56	$0.43	$0.50
Earnings per share of common stock (diluted) (b)				
Continuing operations	$0.67	$0.55	$0.43	$0.49
Discontinued operations	—	—	—	0.01
Total earnings per share (diluted)	$0.67	$0.55	$0.43	$0.50

(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 because the computation is based on the weighted average common shares outstanding during each quarter.

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

CORPORATE DEVELOPMENTS

INTRODUCTION

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

Our utility energy segment primarily consists of Wisconsin Electric and Wisconsin Gas, both doing business under the trade name of "We Energies." We generate and distribute electricity in Wisconsin and the Upper Peninsula of Michigan and we distribute natural gas in Wisconsin. 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 under our PTF strategy.

CORPORATE STRATEGY

Business Opportunities

We have three primary investment opportunities and earnings streams: our regulated utility business; our investment in ATC; and our generation plants within our non-utility energy segment.

Our regulated utility business primarily consists of electric generation assets and the electric and gas distribution assets that serve the electric and gas customers of Wisconsin Electric and Wisconsin Gas. During 2012, our regulated utility earned $647.7 million of operating income. Over the next three years, we expect to invest approximately $2.0 billion in this business to construct renewable generation, to convert the fuel source for VAPP from coal to natural gas, to update the electric and gas distribution infrastructure, and for other utility projects.

We have a $378.3 million investment in ATC, which represents a 26.2% ownership interest. Our 2012 pre-tax earnings from ATC totaled $65.7 million and we received $52.6 million in dividends from ATC. Over the next three years, we expect to make capital contributions of approximately $40 million in ATC as it continues to invest in transmission projects. During the same period, we expect to invest $47 million in ATC through undistributed earnings.

Our non-utility energy segment consists primarily of the four generation plants constructed as part of our PTF strategy. All four plants have been placed in service and are being leased to Wisconsin Electric under long-term leases that run for 25 years (PWGS 1 and PWGS 2) and 30 years (OC 1 and OC 2). We recognize revenues on a levelized basis over the life of the lease. During 2013, we expect this segment's operating income to be between $360 million and $365 million. The PTF strategy was developed with the primary goal of constructing these power plants. Over the next three years, we do, however, expect to invest approximately $97 million in this segment on smaller capital projects, including the Oak Creek expansion fuel flexibility project. For additional information on this project, see Factors Affecting Results, Liquidity and Capital Resources -- Other Matters.

RESULTS OF OPERATIONS

CONSOLIDATED EARNINGS

The following table compares our operating income by business segment and our net income for 2012, 2011 and 2010:

Wisconsin Energy Corporation	2012	2011	2010
	(Millions of Dollars)		
Utility Energy	$647.7	$544.8	$564.0
Non-Utility Energy	358.8	348.9	252.4
Corporate and Other	(6.2)	(6.4)	(6.0)
Total Operating Income	1,000.3	887.3	810.4
Equity in Earnings of Transmission Affiliate	65.7	62.5	60.1
Other Income and Deductions, net	34.8	62.7	40.2
Interest Expense, net	248.2	235.8	206.4
Income from Continuing Operations Before Income Taxes	852.6	776.7	704.3
Income Tax Expense	306.3	263.9	249.9
Income from Continuing Operations	546.3	512.8	454.4
Income from Discontinued Operations, Net of Tax	—	13.4	2.1
Net Income	$546.3	$526.2	$456.5
Diluted Earnings Per Share			
Continuing Operations	$2.35	$2.18	$1.92
Discontinued Operations	—	0.06	0.01
Total Diluted Earnings Per Share	$2.35	$2.24	$1.93

An analysis of contributions to operating income by segment and a more detailed analysis of results follows.

UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

The following table summarizes our utility energy segment's operating income during 2012, 2011 and 2010:

Utility Energy Segment	2012	2011	2010
	(Millions of Dollars)		
Operating Revenues			
Electric	$3,193.9	$3,211.3	$2,936.3
Gas	962.6	1,181.2	1,190.2
Other	34.3	39.0	38.8
Total Operating Revenues	4,190.8	4,431.5	4,165.3
Operating Expenses			
Fuel and Purchased Power	1,103.8	1,174.5	1,104.7
Cost of Gas Sold	545.8	728.7	751.5
Other Operation and Maintenance	1,476.5	1,613.4	1,587.0

Depreciation and Amortization	296.4	257.0	251.4
Property and Revenue Taxes	120.6	113.1	105.1
Total Operating Expenses	3,543.1	3,886.7	3,799.7
Amortization of Gain	—	—	198.4
Operating Income	$647.7	$544.8	$564.0

2012 vs. 2011: Our utility energy segment contributed $647.7 million of operating income during 2012 compared with $544.8 million of operating income during 2011. The increase in operating income was primarily caused by decreased other operation and maintenance expense and decreased fuel and purchased power expenses.

2011 vs. 2010: Our utility energy segment contributed $544.8 million of operating income during 2011 compared with $564.0 million of operating income during 2010. The decrease in operating income was primarily caused by increased other operation and maintenance expense and unfavorable weather during 2011 as compared to 2010, partially offset by wholesale electric pricing increases and electric sales growth.

Electric Utility Gross Margin

The following table compares our electric utility gross margin during 2012 with similar information for 2011 and 2010, including a summary of electric operating revenues and electric sales by customer class:

	Electric Revenues and Gross Margin			MWh Sales		
Electric Utility Operations	2012	2011	2010	2012	2011	2010
	(Millions of Dollars)			(Thousands)		
Customer Class						
Residential	$1,163.9	$1,159.2	$1,114.3	8,317.7	8,278.5	8,426.3
Small Commercial/Industrial	1,013.6	1,006.9	922.2	8,860.0	8,795.8	8,823.3
Large Commercial/Industrial	744.3	763.7	677.1	9,710.7	9,992.2	9,961.5
Other - Retail	22.8	22.9	21.9	154.8	153.6	155.3
Total Retail	2,944.6	2,952.7	2,735.5	27,043.2	27,220.1	27,366.4
Wholesale - Other	144.4	154.0	134.6	1,566.6	2,024.8	2,004.6
Resale - Utilities	53.4	69.5	40.4	1,642.4	2,065.7	1,103.8
Other Operating Revenues	51.5	35.1	25.8	—	—	—
Total	3,193.9	3,211.3	2,936.3	30,252.2	31,310.6	30,474.8
Fuel and Purchased Power						
Fuel	541.6	644.4	570.5			
Purchased Power	548.7	514.8	521.0			
Total Fuel and Purchased Power	1,090.3	1,159.2	1,091.5			
Total Electric Gross Margin	$2,103.6	$2,052.1	$1,844.8			
Weather - Degree Days (a)						
Heating (6,662 Normal)				5,704	6,633	6,183
Cooling (696 Normal)				1,041	793	944

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

Electric Utility Revenues and Sales

2012 vs. 2011: Our electric utility operating revenues decreased by $17.4 million, or 0.5%, when compared to 2011. The most significant factors that caused a change in revenues were:

- Favorable weather as compared to the prior year that increased electric revenues by an estimated $28.5 million.
- Other operating revenues increased by approximately $16.4 million, driven by the $25.9 million amortization of a settlement with the DOE. For additional information on the DOE settlement, see Factors Affecting Results, Liquidity and Capital Resources -- Nuclear Operations.
- A planned outage at an iron ore mine of our largest customer and the conversion to self-generation of two other large customers decreased electric revenues by an estimated $20.4 million.
- A $16.2 million reduction in sales for resale due to reduced sales into the MISO Energy Markets.

- Lower MWh sales to our wholesale customers, which decreased revenue by an estimated $12.4 million as compared to 2011.

As measured by cooling degree days, 2012 was 49.6% warmer than normal, and 31.3% warmer than 2011. We believe the warmer summer weather was the primary reason for the 0.5% increase in residential sales and the 0.7% increase in small commercial/industrial sales. The increase due to warmer summer weather was partially offset by reduced sales from warmer winter weather in the first quarter of 2012 as compared to the first quarter of 2011.

Sales to our large commercial/industrial customers decreased by 2.8% primarily due to the planned outage at an iron ore mine of our largest customer and the conversion to self-generation of two other large customers. Excluding sales to these three customers, MWh sales to large commercial/industrial customers increased by 1.1%. Wholesale sales decreased primarily due to the low market price of power in 2012 as compared to 2011, which caused some of these customers to obtain energy from the MISO market rather than through our contracts. The reduction did not impact the majority of revenue received from these customers, which is tied to demand. The lower market price of power also reduced our ability to sell energy into the MISO Energy Markets.

2011 vs. 2010: Our electric utility operating revenues increased by $275.0 million, or 9.4%, when compared to 2010. The most significant factors that caused a change in revenues were:

- 2011 increase of approximately $198.4 million, reflecting the reduction of Point Beach bill credits to retail customers. For information on the bill credits, see Amortization of Gain below.
- Net pricing increases totaling $48.8 million, which includes rates related to our 2010 fuel recovery request that became effective March 25, 2010, and our request to review 2011 fuel costs that became effective April 29, 2011. For information on these rate orders, see Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters.
- Unfavorable weather as compared to 2010 that decreased electric revenues by an estimated $40.5 million.
- A $20.4 million increase in revenue from energy sold into the MISO Energy Markets, which was driven by increased MWh generation from our Oak Creek expansion units.
- Net economic growth that increased electric revenues by an estimated $16.2 million as compared to 2010.
- Higher MWh sales to our wholesale customers, which increased revenue by an estimated $10.4 million as compared to 2010.

As measured by cooling degree days, 2011 was 11.8% warmer than normal, but 16.0% cooler than 2010. The 1.8% decrease in residential sales volumes in 2011 is primarily attributable to weather. The estimated 1.8% impact of cooler summer weather on our small commercial/industrial sales volumes was almost entirely offset by an estimated 1.5% increase in sales due to modest economic growth. Increased sales to our largest customers, two iron ore mines, accounted for the increase in sales to our large commercial/industrial customers. If these sales are excluded, sales to our large commercial/industrial customers decreased by approximately 1.2% for 2011 as compared to 2010 primarily because of previously announced plant closings.

Electric Fuel and Purchased Power Expenses

2012 vs. 2011: Our electric fuel and purchased power costs decreased by $68.9 million, or approximately 5.9%, when compared to 2011. This decrease was primarily caused by a 3.4% decrease in total MWh sales as well as a reduction in our average cost of fuel and purchased power because of lower natural gas prices.

2011 vs. 2010: Our electric fuel and purchased power costs increased by $67.7 million, or approximately 6.2%, when compared to 2010. This increase was primarily caused by a 2.7% increase in total MWh sales as well as increased coal and related transportation costs, partially offset by lower natural gas prices.

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 2012, 2011 and 2010. Operating revenues and cost of gas sold has declined over the last three years due to the decline in the commodity cost of natural gas during this three year period.

Gas Utility Operations	2012	2011	2010
	(Millions of Dollars)		
Operating Revenues	$962.6	$1,181.2	$1,190.2
Cost of Gas Sold	545.8	728.7	751.5
Gross Margin	$416.8	$452.5	$438.7

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 2012, 2011 and 2010:

	Gross Margin			Therm Deliveries		
Gas Utility Operations	2012	2011	2010	2012	2011	2010
	(Millions of Dollars)			(Millions)		
Customer Class						
Residential	$267.9	$290.2	$282.2	676.4	776.8	741.2
Commercial/Industrial	88.8	101.5	95.8	390.6	461.7	429.6
Interruptible	1.7	1.8	2.2	14.6	16.0	19.4
Total Retail	358.4	393.5	380.2	1,081.6	1,254.5	1,190.2
Transported Gas	52.9	52.6	51.3	1,140.4	899.6	914.9
Other Operating	5.5	6.4	7.2	—	—	—
Total	$416.8	$452.5	$438.7	2,222.0	2,154.1	2,105.1
Weather - Degree Days (a)						
Heating (6,662 Normal)				5,704	6,633	6,183

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

2012 vs. 2011: Our total retail gas margin decreased by $35.1 million, or approximately 8.9%, when compared to 2011 primarily because of a decrease in sales volumes as a result of warmer winter weather. As measured by heating degree days, 2012 was 14.0% warmer than 2011 and 14.4% warmer than normal.

Transported gas volumes increased by 26.8% when compared to 2011. Virtually all of the volume increase related to gas used in electric generation, which has a small impact on margin.

2011 vs. 2010: Our gas margin increased by $13.8 million, or approximately 3.1%, when compared to 2010 primarily because of an increase in sales volumes as a result of colder winter weather in 2011 as compared to 2010. As measured by heating degree days, 2011 was 7.3% colder than 2010 and 0.3% colder than normal.

Other Operation and Maintenance Expense

2012 vs. 2011: Our other operation and maintenance expense decreased by $136.9 million, or approximately 8.5%, when compared to 2011. This decrease is primarily due to the one year suspension of $148 million of amortization expense on certain regulatory assets as authorized under our 2012 Wisconsin Rate Case. For additional information on the 2012 rate case, see Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters.

Our utility operation and maintenance expenses are influenced by, among other things, labor costs, employee benefit costs, plant outages and amortization of regulatory assets. We expect our 2013 other operation and maintenance expense to stay fairly flat because we anticipate that the 2013 Wisconsin Rate Case reinstatement of amortization on certain regulatory assets will be offset by an extension of the recovery period for certain regulatory assets and a significant reduction of escrowed bad debt expense.

2011 vs. 2010: Our other operation and maintenance expense increased by $26.4 million, or approximately 1.7%, when compared to 2010. Higher maintenance costs at one of our natural gas peaking plants, increased spending on forestry work for our electric distribution system and increased costs associated with the amortization of deferred PTF costs related to wholesale and Michigan customers were the primary drivers of the increase.

Depreciation and Amortization Expense

2012 vs. 2011: Depreciation and Amortization expense increased by $39.4 million, or approximately 15.3%, when compared to 2011. This increase was primarily because of an overall increase in utility plant in service. The Glacier Hills Wind Park went into service in December 2011. In addition, the emission control equipment for units 5 and 6 of the Oak Creek AQCS project went into service in March 2012, and for units 7 and 8 in September 2012. For additional information, see Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters -- Oak Creek Air Quality Control System.

We expect depreciation and amortization expense to increase in 2013 primarily as a result of an increase in utility plant in service related to the Oak Creek AQCS project, which will have been in service a full year.

2011 vs. 2010: Depreciation and Amortization expense increased by $5.6 million, or approximately 2.2%, when compared to 2010. This increase was primarily because of an overall increase in utility plant in service.

Amortization of Gain

In connection with the September 2007 sale of Point Beach, we reached an agreement with our regulators to allow for the net gain on the sale to be used for the benefit of our customers. The majority of the benefits were returned to customers in the form of bill credits. The net gain was originally recorded as a regulatory liability, and it was amortized to the income statement as we issued bill credits to customers. When the bill credits were issued to customers, we transferred cash from the restricted accounts to the unrestricted accounts, adjusted for taxes. All bill credits associated with the sale of Point Beach were applied to customers as of December 31, 2010, and as a result, the Amortization of Gain was zero during 2012 and 2011 as compared to $198.4 million during 2010.

NON-UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

Our non-utility energy segment consists primarily of our PTF units (PWGS 1, PWGS 2, OC 1 and OC 2). PWGS 1 and PWGS 2 were placed in service in July 2005 and May 2008, respectively. The common facilities associated with the Oak Creek expansion include the water intake system, which was placed in service in January 2009, the coal handling system, which was placed in service in November 2007, and other smaller assets. OC 1 and OC 2 were placed in service in February 2010 and January 2011, respectively.

The table below reflects:

- A full year's earnings for 2012, 2011 and 2010 for:
  - PWGS 1;
  - PWGS 2;
  - the coal handling system for the Oak Creek expansion; and
  - the water intake system for the Oak Creek expansion.

- A full year's earnings for 2012 and 2011 and approximately eleven months of earnings for 2010 for OC 1; and
- A full year's earnings for 2012 and approximately eleven and a half months of earnings for 2011 for OC 2.

This segment reflects the lease revenues on the new units as well as the depreciation expense. Operating and maintenance costs and limited management fees associated with the plants are the responsibility of Wisconsin Electric and are recorded in the utility segment.

	2012	2011	2010
	(Millions of Dollars)		
Operating Revenues	$439.9	$435.1	$320.2
Operation and Maintenance Expense	14.0	13.7	14.3
Depreciation Expense	67.1	72.5	53.5
Operating Income (Loss)	$358.8	$348.9	$252.4

Non-utility energy segment operating income increased $9.9 million, or approximately 2.8%, primarily because of a decrease in depreciation expense related to finalized depreciable lives of the Oak Creek expansion units and a full year's earnings in 2012 for OC 2.

In 2013, we expect our non-utility energy segment operating revenue to increase approximately 2% to 3% to reflect the final approved construction costs for the Oak Creek expansion as part of the 2013 Wisconsin Rate Case. For further information, see Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters.

CORPORATE AND OTHER CONTRIBUTION TO OPERATING INCOME

2012 vs. 2011: Corporate and other affiliates had an operating loss of $6.2 million in 2012 compared with an operating loss of $6.4 million in 2011.

2011 vs. 2010: Corporate and other affiliates had an operating loss of $6.4 million in 2011 compared with an operating loss of $6.0 million in 2010.

CONSOLIDATED OTHER INCOME AND DEDUCTIONS, NET

Other Income and Deductions, net	2012	2011	2010
	(Millions of Dollars)		
AFUDC - Equity	$35.3	$59.4	$32.5
Gain on Property Sales	2.7	2.4	4.4
Other, net	(3.2)	0.9	3.3
Total Other Income and Deductions, net	$34.8	$62.7	$40.2

2012 vs. 2011: Other income and deductions, net decreased by approximately $27.9 million, or 44.5%, when compared to 2011. This decrease primarily relates to AFUDC - Equity related to the Glacier Hills Wind Park, which went into service in December 2011, as well as the Oak Creek AQCS project which emission control equipment went into service in March 2012 for units 5 and 6 and September 2012 for units 7 and 8.

During 2013, we expect to see a reduction in AFUDC - Equity as we expect to have fewer large construction projects.

2011 vs. 2010: Other income and deductions, net increased by approximately $22.5 million, or 56.0%, when compared to 2010. The increase in AFUDC - Equity is primarily related to the construction of the Oak Creek AQCS project and the Glacier Hills Wind Park.

CONSOLIDATED INTEREST EXPENSE, NET

Interest Expense, net	2012	2011	2010
	(Millions of Dollars)		
Gross Interest Costs	$264.1	$262.5	$258.7
Less: Capitalized Interest	15.9	26.7	52.3
Interest Expense, net	$248.2	$235.8	$206.4

2012 vs. 2011: Our net interest expense increased by $12.4 million, or 5.3%, as compared to 2011 primarily because of lower capitalized interest. Our capitalized interest decreased by $10.8 million primarily because we stopped capitalizing interest on the Oak Creek AQCS project when the emission control equipment went into service in March 2012 for units 5 and 6 and September 2012 for units 7 and 8, and the Glacier Hills Wind Park which went into service in December 2011.

During 2013, we expect to see higher net interest expense because of a reduction in capitalized interest as a result of the Oak Creek AQCS project emission control equipment going into service in 2012, partially offset by the expected increase in capitalized interest associated with the biomass plant which is expected to go into service by the end of 2013.

2011 vs. 2010: Our gross interest costs increased by $3.8 million, or 1.5%, during 2011, primarily because of higher average long-term debt balances as compared to 2010. In January 2011, we issued $420 million of long-term debt and used the net proceeds to repay short-term debt incurred to finance the construction of OC 2 and for other corporate purposes. In September 2011, Wisconsin Electric issued $300 million of long-term debt and used the net proceeds to repay short-term debt and for other general corporate purposes. In April 2011, we retired $450 million of long-term debt that matured, which partially offset the debt issuances. Our capitalized interest decreased by $25.6 million primarily because we stopped capitalizing interest on OC 2 when it was placed in service in January 2011. As a result, our net interest expense increased by $29.4 million, or 14.2%, as compared to 2010.

CONSOLIDATED INCOME TAX EXPENSE

2012 vs. 2011: Our effective tax rate applicable to continuing operations was 35.9% in 2012 compared to 34.0% in 2011. This increase in our effective tax rate was primarily the result of decreased AFUDC - Equity. For further information, see Note G -- Income Taxes in the Notes to Consolidated Financial Statements. We expect our 2013 annual effective tax rate to be between 37.0% and 38.0%.

2011 vs. 2010: Our effective tax rate applicable to continuing operations was 34.0% in 2011 compared to 35.5% in 2010. This reduction in our effective tax rate was primarily the result of increased AFUDC - Equity.

LIQUIDITY AND CAPITAL RESOURCES

CASH FLOWS

The following table summarizes our cash flows during 2012, 2011 and 2010:

	2012	2011	2010

	(Millions of Dollars)		
Cash Provided by (Used in)			
Operating Activities	$1,173.9	$993.4	$810.4
Investing Activities	$(729.6)	$(892.5)	$(633.5)
Financing Activities	$(422.8)	$(111.3)	$(172.6)

Operating Activities

2012 vs. 2011: Cash provided by operating activities was $1,173.9 million during 2012, which was an increase of $180.5 million over 2011. The largest increases in cash provided by operating activities related to higher net income, higher depreciation expense, and lower contributions to our benefit plans. Combined these items increased operating cash flows by $232.8 million as compared to 2011. Partially offsetting these items, our non-cash charges related to the amortization of certain regulatory assets and liabilities was $148.0 million lower during 2012 as compared to 2011 because the PSCW allowed us to suspend these amortizations in 2012.

2011 vs. 2010: Cash provided by operating activities was $993.4 million during 2011, which was an increase of $183.0 million over 2010. The largest increases in cash provided by operating activities related to higher net income, higher depreciation expense, higher deferred income tax benefits and the elimination of the amortization of the gain on the sale of Point Beach. Combined these items totaled $1,293.2 million during 2011 as compared to $680.4 million during 2010. The largest reduction in cash provided by operating activities related to our contributions to qualified benefit plans. During 2011, we contributed $277.4 million to our qualified benefit plans. We made no contributions to our qualified plans during 2010.

Investing Activities

2012 vs. 2011: Cash used in investing activities was $729.6 million during 2012, which was $162.9 million lower than 2011. This decrease was primarily caused by a decrease in capital expenditures and a decrease in our restricted cash. Our capital expenditures decreased by $123.8 million in 2012 compared to 2011, primarily because of decreased spending on the Oak Creek AQCS project which went into service in March and September of 2012. In 2011, we received $45.5 million in proceeds from the settlement with the DOE. The proceeds were treated as restricted cash, which was recorded as cash used in investing activities. In 2012, we released $42.8 million of the proceeds through bill credits and the reimbursement of costs. The decrease was offset by a reduction in proceeds from asset sales. In 2011, we received proceeds from asset sales totaling $41.5 million, which primarily relates to the sale of our interest in Edgewater Generating Unit 5, as compared to proceeds of $8.7 million in 2012.

The following table identifies capital expenditures by year:

Capital Expenditures	2012	2011	2010
	(Millions of Dollars)		
Utility	$697.3	$792.2	$687.0
We Power	5.5	31.2	109.3
Other	4.2	7.4	1.9
Total Capital Expenditures	$707.0	$830.8	$798.2

2011 vs. 2010: Cash used in investing activities was $892.5 million during 2011, which was $259.0 million higher than 2010. This increase in cash used primarily reflects changes in restricted cash and increased capital expenditures. During 2011, our restricted cash increased by $37.2 million primarily because of the nuclear fuel settlement we received from the DOE. During 2010, our restricted cash decreased by $186.2 million due to the release of restricted cash related to the Point Beach bill credits. In addition, capital expenditures increased by approximately $32.6 million during 2011 as compared to 2010 primarily due to increased spending related to the construction of the Oak Creek AQCS project and the Glacier Hills Wind Park in 2011 as compared to 2010.

Financing Activities

The following table summarizes our cash flows from financing activities:

	2012	2011	2010
	(Millions of Dollars)		
Net Increase (Decrease) in Debt	$(43.8)	$265.4	$71.1
Dividends on Common Stock	(276.3)	(242.0)	(187.0)
Common Stock Repurchased, Net	(103.4)	(139.5)	(65.7)
Other	0.7	4.8	9.0
Cash (Used in) Provided by Financing	$(422.8)	$(111.3)	$(172.6)

2012 vs. 2011: Cash used in financing activities was $422.8 million during 2012, compared to $111.3 million during 2011. In 2012, we issued $251.8 million in long term debt, including $250.0 million by Wisconsin Electric, and used the proceeds to repay short-term debt and for other general corporate purposes. In 2011, we issued $720.0 million of long-term debt. In addition, we retired $466.6 million of long-term debt in 2011. Short-term debt decreased $275.3 million in 2012 compared to a $12.0 million increase in 2011.

Our common stock dividends increased in 2012 as we raised our quarterly dividend rate by 15.4%. In January 2013, our Board of Directors approved an increase in our quarterly common stock dividend of $.04 per share, or approximately 13.3%.

In addition, on May 5, 2011, our Board of Directors authorized a share repurchase program for up to $300 million of our common stock through the end of 2013. Funds for the repurchases are expected to continue to come from internally generated funds and working capital supplemented, if required in the short-term, by the sale of commercial paper. The repurchase program does not obligate Wisconsin Energy to acquire any specific number of shares and may be suspended or terminated by the Board of Directors at any time. In 2012, we repurchased approximately 1.5 million shares in the open market pursuant to this program at a total cost of $51.8 million, compared to 3.2 million shares at a cost of $100 million in 2011.

2011 vs. 2010: Cash used in financing activities was $111.3 million during 2011, compared to $172.6 million during 2010. During 2011, we issued a total of $720.0 million of long-term debt and retired $466.6 million of long-term debt. The net proceeds from the new issuance of debt were used to repay short-term debt and for other corporate purposes.

Our common stock dividends increased in 2011 as we raised our dividend rate by 30.0%.

No new shares of Wisconsin Energy's common stock were issued in 2012, 2011 or 2010. During these years, our independent plan agents purchased, in the open market, 2.8 million shares at a cost of $101.4 million, 3.0 million shares at a cost of $93.9 million and 5.8 million shares at a cost of $156.6 million, respectively, to fulfill exercised stock options and restricted stock awards. In 2012, 2011 and 2010, we received proceeds of $49.8 million, $54.4 million and $90.9 million, respectively, related to the exercise of stock options. In addition, we instructed our independent agents to purchase shares of our common stock in the open market to satisfy our obligations under our stock purchase and dividend reinvestment plan and various employee benefit plans.

CAPITAL RESOURCES AND REQUIREMENTS

Working Capital

As of December 31, 2012, our current liabilities exceeded our current assets by approximately $129.4 million. Included in our current liabilities is approximately $412.1 million of long-term debt due currently. We do not expect this to have any impact on our liquidity because we believe we have adequate back-up lines of credit in place for on-going operations. We also have access to the capital markets to finance our construction program and to refinance current maturities of long-term debt if necessary.

Liquidity

We anticipate meeting our capital requirements during 2013 and beyond primarily through internally generated funds and short-term borrowings, supplemented by the issuance of intermediate or long-term debt securities depending on market conditions and other factors.

We currently have access to the 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 currently believe that we have adequate capacity to fund our operations for the foreseeable future through our existing borrowing arrangements, access to capital markets and internally generated cash.

Wisconsin Energy, Wisconsin Electric and Wisconsin Gas maintain bank back-up credit facilities, which provide liquidity support for each company's obligations with respect to commercial paper and for general corporate purposes.

As of December 31, 2012, we had approximately $1.2 billion of available, undrawn lines under our bank back-up credit facilities. As of December 31, 2012, we had approximately $394.6 million of commercial paper outstanding on a consolidated basis that was supported by the available lines of credit. During 2012, our maximum commercial paper outstanding was $669.9 million with a weighted-average interest rate of 0.28%. For additional information regarding our commercial paper balances during 2012, see Note J -- Short-Term Debt in the Notes to Consolidated Financial Statements.

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 as of December 31, 2012:

Company	Total Facility	Letters of Credit	Credit Available	Facility Expiration
	(Millions of Dollars)			
Wisconsin Energy	$400.0	$0.4	$399.6	December 2017
Wisconsin Electric	$500.0	$5.9	$494.1	December 2017
Wisconsin Gas	$350.0	$—	$350.0	December 2017

On December 12, 2012, Wisconsin Energy entered into an unsecured five-year $400 million bank back-up credit facility to replace a $450 million three-year credit facility with an expiration date of December 2013. This new facility will expire in December 2017.

On December 12, 2012, Wisconsin Electric entered into an unsecured five-year $500 million bank back-up credit facility to replace a $500 million three-year credit facility with an expiration date of December 2013. This new facility will expire in December 2017.

On December 12, 2012, Wisconsin Gas entered into an unsecured five-year $350 million bank back-up credit facility to replace a $300 million three-year credit facility with an expiration date of December 2013. This new facility will expire in December 2017.

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

The following table shows our capitalization structure as of December 31, 2012 and 2011, as well as an adjusted capitalization structure that we believe is consistent with the manner in which the rating agencies currently view Wisconsin Energy's 2007 Series A Junior Subordinated Notes due 2067 (Junior Notes):

Capitalization Structure	2012 Actual	2012 Adjusted	2011 Actual	2011 Adjusted
	(Millions of Dollars)			
Common Equity	$4,135.1	$4,385.1	$3,963.3	$4,213.3
Preferred Stock of Subsidiary	30.4	30.4	30.4	30.4
Long-Term Debt (including current maturities)	4,865.9	4,615.9	4,646.9	4,396.9
Short-Term Debt	394.6	394.6	669.9	669.9
Total Capitalization	$9,426.0	$9,426.0	$9,310.5	$9,310.5
Total Debt	$5,260.5	$5,010.5	$5,316.8	$5,066.8
Ratio of Debt to Total Capitalization	55.8 %	53.2 %	57.1 %	54.4 %

For a summary of the interest rate, maturity and amount outstanding of each series of our long-term debt on a consolidated basis, see the Consolidated Statements of Capitalization.

Included in Long-Term Debt on our Consolidated Balance Sheet as of December 31, 2012 and 2011 is $500 million aggregate principal amount of the Junior Notes. The adjusted presentation attributes $250 million of the Junior Notes to Common Equity and $250 million to Long-Term Debt. We believe this presentation is consistent with the 50% or greater equity credit the majority of rating agencies currently attribute to the Junior Notes.

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

As described in Note H -- 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.

Wisconsin Electric is the obligor under two series of tax exempt pollution control refunding bonds in outstanding principal amounts of $147 million. In August 2009, Wisconsin Electric terminated letters of credit that provided credit and liquidity support for the bonds, which resulted in a mandatory tender of the bonds. Wisconsin Electric issued commercial paper to fund the purchase of the bonds. As of December 31, 2012, the repurchased bonds were still outstanding, but were reported as a reduction in our consolidated long-term debt because they are held by Wisconsin Electric. Depending on market conditions and other factors, Wisconsin Electric may change the method used to determine the interest rate on the bonds and have them remarketed to third parties.

Bonus Depreciation Provisions

As a result of the enactment of tax legislation extending the bonus depreciation rules, we recognized increased federal tax depreciation through 2012 relating to assets placed into service including the Glacier Hills Wind Park, OC 1, OC 2 and the Oak Creek AQCS project. As a result of this increased federal tax depreciation we did not make federal income tax payments for 2012 and do not anticipate making federal income tax payments for 2013. The American Taxpayer Relief Act of 2012 was signed into law on January 2, 2013, which extended the 50% bonus depreciation rules to include assets placed in service in 2013.

Credit Rating Risk

We do not have any credit agreements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. We do have certain agreements in the form of commodity contracts and employee benefit plans that could require collateral or a termination payment in the event of a credit rating change to below BBB- at Standard & Poor's Ratings Services (S&P) and/or Baa3 at Moody's Investor Service (Moody's). As of December 31, 2012, we estimate that the collateral or the termination payments required under these agreements totaled approximately $225.7 million. Generally, collateral may be provided by a Wisconsin Energy guaranty, letter of credit or cash. We also have other commodity contracts that in the event of a credit rating downgrade could result in a reduction of our unsecured credit granted by counterparties.

In addition, access to capital markets at a reasonable cost is determined in large part by credit quality. Any credit ratings downgrade could impact our ability to access capital markets.

In November 2012, Moody's affirmed the ratings of Wisconsin Gas (commercial paper, P-1; senior unsecured, A2). In December 2012, Moody's affirmed the ratings of Wisconsin Energy (commercial paper, P-2; senior unsecured, A3; junior unsecured, Baa1), Wisconsin Electric (commercial paper, P-1; senior unsecured, A2), Elm Road Generating Station Supercritical, LLC (ERGSS) (senior notes, A2) and Wisconsin Energy Capital Corporation (WECC) (senior unsecured, A3). Moody's affirmed the stable ratings outlook assigned to each company.

In June 2012, S&P affirmed the ratings of Wisconsin Energy (commercial paper, A-2; senior unsecured, BBB+; junior unsecured, BBB), Wisconsin Electric (commercial paper, A-2; senior unsecured, A-), Wisconsin Gas (commercial paper, A-2; senior unsecured, A-) and ERGSS (senior notes, A-). S&P also revised the ratings outlooks assigned to each company from stable to positive.

In June 2012, Fitch Ratings (Fitch) affirmed the ratings of Wisconsin Energy (commercial paper, F2; senior unsecured, A-; junior unsecured, BBB), Wisconsin Electric (commercial paper, F1; senior unsecured, A+), Wisconsin Gas (commercial paper, F1; senior unsecured, A+), WECC (senior unsecured, A-) and ERGSS (senior notes, A+). Fitch also affirmed the stable ratings outlooks assigned to each company.

Subject to other factors affecting the credit markets as a whole, we believe our current 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. Any rating can be revised upward or downward or withdrawn at any time by a rating agency.

Capital Requirements

Capital Expenditures: Our estimated 2013, 2014 and 2015 capital expenditures are as follows:

Capital Expenditures	2013	2014	2015
	(Millions of Dollars)		
Utility	$655.9	$589.0	$741.0
We Power	30.6	34.3	28.6
Other	6.2	7.5	8.5

Total	$692.7	$630.8	$778.1

The majority of spending consists of upgrading our electric and gas distribution systems. Our actual future long-term capital requirements may vary from these estimates because of changing environmental and other regulations such as air quality standards, renewable energy standards and electric reliability initiatives that impact our utility energy segment.

Common Stock Matters: During 2013, we expect to continue to repurchase our common stock under the share repurchase program approved by the Board on May 5, 2011, and to pay a quarterly dividend of $0.34 per share as approved by the Board in January 2013.

Investments in Outside Trusts: We use outside trusts to fund our pension and certain other post-retirement obligations. These trusts had investments of approximately $1.7 billion as of December 31, 2012. These trusts hold investments that are subject to the volatility of the stock market and interest rates.

During 2012, we contributed $95.6 million to our qualified pension plans and $4.4 million to our qualified Other Post-Retirement Employee Benefit (OPEB) plans. During 2011, we contributed $236.4 million to our qualified pension plans and $41.0 million to our qualified OPEB plans. Future contributions to the plans will be dependent upon many factors, including the performance of existing plan assets and long-term discount rates. For additional information, see Note M -- Benefits in the Notes to Consolidated Financial Statements.

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

Contractual Obligations/Commercial Commitments: We have the following contractual obligations and other commercial commitments as of December 31, 2012:

	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)	$9,100.8	$647.8	$1,171.1	$504.6	$6,777.3
Capital Lease Obligations (c)	256.3	40.4	85.4	59.1	71.4
Operating Lease Obligations (d)	47.1	6.5	7.9	6.8	25.9
Purchase Obligations (e)	12,708.3	887.0	1,341.8	1,052.6	9,426.9
Other Long-Term Liabilities	989.1	101.7	199.1	198.9	489.4
Total Contractual Obligations	$23,101.6	$1,683.4	$2,805.3	$1,822.0	$16,790.9

(a) The amounts included in the table are calculated using current market prices, forward curves and other estimates.

(b) Principal and interest payments on Long-Term Debt (excluding capital lease obligations).

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

(d) Operating Lease Obligations for power purchase commitments and rail car leases.

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

The table above does not include liabilities related to the accounting treatment for uncertainty in income taxes because we are not able to make a reasonably reliable estimate as to the amount and period of related future payments at this time. For additional information regarding these liabilities, refer to Note G -- Income Taxes in the Notes to Consolidated Financial Statements in this report.

Obligations for utility operations have historically been included as part of the rate-making process and therefore are generally recoverable from customers.

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:

Regulatory Recovery: Our utility energy segment accounts for its regulated operations in accordance with accounting guidance for regulated entities. Our rates are determined by regulatory authorities. Our primary regulator is the PSCW. Regulated entities are allowed 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. In general, regulatory assets are recovered in a period between one to eight years. Regulatory assets associated with pension and OPEB expenses are amortized as a component of pension and OPEB expense. 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. We record these items as regulatory liabilities. As of December 31, 2012, our regulatory assets totaled $1,380.3 million and our regulatory liabilities totaled $868.3 million.

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

Wisconsin's retail electric fuel cost adjustment procedure mitigates some of Wisconsin Electric's risk of electric fuel cost fluctuation. Effective January 1, 2011, the PSCW implemented new fuel rules which allow for a deferral of prudently incurred fuel costs that fall outside of a symmetrical band (plus or minus 2%). Under the rules, any over or under-collection of fuel costs deferred at the end of the year would be incorporated into fuel cost recovery rates in future years. For information regarding the fuel rules, see Utility Rates and Regulatory Matters -- Wisconsin Fuel Rules.

Natural Gas Costs: Higher natural gas costs could 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. Higher natural gas costs may also lead to increased energy efficiency investments by our customers to reduce utility usage and/or fuel substitution.

As part of its December 2012 rate order, the PSCW authorized continued use of the escrow method of accounting for bad debt costs through December 31, 2014. The escrow method of accounting for bad debt costs allows for deferral of Wisconsin residential bad debt expense that exceeds or is less than amounts allowed in rates.

As a result of GCRMs, our gas utility operations 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. For information concerning the natural gas utilities' GCRMs, see Utility Rates and Regulatory Matters.

Weather: Our Wisconsin utility rates are set by the PSCW based upon estimated temperatures which approximate 20-year averages. Wisconsin Electric's electric revenues and sales 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 and sales 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 2012, 2011 and 2010, 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 as of December 31, 2012. Borrowing levels under these arrangements vary from period to period depending on 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 as of December 31, 2012 of our outstanding portfolio of commercial paper and variable rate long-term debt. As of December 31, 2012, we had $394.6 million of commercial paper outstanding with a weighted average interest rate of 0.30% and $147.0 million of variable-rate long-term debt outstanding with a weighted average interest rate of 0.50%. A one-percentage point change in interest rates would cause our annual interest expense to increase or decrease by approximately $5.4 million.

Marketable Securities Return: We use various trusts to fund our pension and OPEB obligations. These trusts invest in debt and equity securities. Changes in the market prices of these assets can affect future pension and OPEB expenses. Additionally, future contributions can also be affected by the investment returns on trust fund assets. We believe that the financial risks associated with investment returns would be partially mitigated through future rate actions by our various utility regulators.

The fair value of our trust fund assets as of December 31, 2012 was approximately:

Wisconsin Energy Corporation	Millions of Dollars
Pension trust funds	$1,385.4
Other post-retirement benefits trust funds	$285.4

The expected long-term rate of return on plan assets for 2013 is 7.25% and 7.5%, respectively, for the pension and OPEB plans.

Fiduciary oversight of the pension and OPEB trust fund investments is the responsibility of an Investment Trust Policy Committee. The Committee works with external actuaries and investment consultants on an ongoing basis to establish and monitor investment strategies and target asset allocations. Forecasted cash flows for plan liabilities are regularly updated based on annual valuation results. Target asset allocations are determined utilizing projected benefit payment cash flows and risk analyses of appropriate investments. The targeted asset allocations are intended to reduce risk, provide long-term financial stability for the plans and maintain funded levels which meet long-term plan obligations while preserving sufficient liquidity for near-term benefit payments. Investment strategies utilize a wide diversification of asset types and qualified external investment managers.

We consult with our investment advisors on an annual basis to help us forecast expected long-term returns on plan assets by reviewing actual historical returns and calculating expected total trust returns using the weighted-average of long-term market returns for each of the major target asset categories utilized in the fund.

Economic Conditions: Our service territory is within the state of Wisconsin and the Upper Peninsula of Michigan. We are exposed to market risks in the regional midwest economy.

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

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

POWER THE FUTURE

All of the PTF units have been placed into service and are positioned to provide a significant portion of our future generation needs. The PTF units include PWGS 1, PWGS 2, OC 1 and OC 2.

As part of our 2013 Wisconsin Rate Case, the PSCW determined that 100% of the construction costs for our Oak Creek expansion units were prudently incurred, and approved the recovery in rates of more than 99.5% of these costs. In addition, the PSCW deferred the final decision regarding $24 million related to the fuel flexibility project until a future rate proceeding. See Other Matters below for additional information about the fuel flexibility project.

We are recovering our costs in these units through lease payments associated with PWGS 1, PWGS 2, OC 1 and OC 2 that are billed from We Power to Wisconsin Electric and then recovered in Wisconsin Electric's rates as authorized by the PSCW, the MPSC and FERC. 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 Oak Creek Units.

Wisconsin Electric operates PWGS 1, PWGS 2, OC 1 and OC 2 and is authorized by the PSCW to fully recover prudently incurred operating and maintenance costs in its Wisconsin electric rates. As the operator of the units, Wisconsin Electric may request We Power make capital improvements to or further investments in the units. Under the lease terms, we would expect the costs of any capital improvements or further investments to be added to the lease payments, and ultimately to be recovered in Wisconsin Electric's rates.

We Power assigned its warranty rights to Wisconsin Electric upon turnover of each of the Oak Creek expansion units. Although the warranty periods for both of the units have expired, Wisconsin Electric and Bechtel continue to work through outstanding warranty claims. Wisconsin Electric's warranty claim for the costs incurred to repair steam turbine corrosion damage identified on both units is expected to be resolved through a binding arbitration hearing scheduled for October 2013.

In accordance with the contract between We Power and Bechtel, final acceptance of the units cannot occur until, among other things, all disputes have been settled. Pursuant to the settlement agreement entered into with Bechtel in December 2009, a final payment of $2.5 million per unit will be due upon final acceptance.

UTILITY RATES AND REGULATORY MATTERS

The PSCW regulates our retail electric, natural gas and steam 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, 6% are regulated by the MPSC and the balance of our electric revenues is regulated by FERC. In Wisconsin, a general rate case is typically filed every two years. All of our natural gas and steam 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/.

2013 Wisconsin Rate Case: On March 23, 2012, Wisconsin Electric and Wisconsin Gas initiated rate proceedings with the PSCW. On December 20, 2012, the PSCW approved the following rate adjustments:

- A net bill increase related to non-fuel costs for Wisconsin Electric's Wisconsin retail electric customers of approximately $70 million (2.6%) for 2013. This amount reflects an offset of approximately $63 million (2.3%) related to the proceeds of a renewable energy cash grant Wisconsin Electric expects to receive under the NDAA upon completion of its biomass facility currently under construction. Absent this offset, the retail electric rate increase for non-fuel costs is approximately $133 million (4.8%) for 2013.
- Absent an adjustment for any remaining energy cash credits, an electric rate increase for Wisconsin Electric's Wisconsin electric customers of approximately $28 million (1.0%) for 2014.
-

Recovery of a forecasted increase in fuel costs of approximately $44 million (1.6%) for 2013. Wisconsin Electric will make an annual fuel cost filing, as required, for 2014.

- A rate decrease of approximately $8 million (1.9%) for Wisconsin Electric's natural gas customers for 2013, with no rate adjustment in 2014.
- A rate decrease of approximately $34 million (5.5%) for Wisconsin Gas' natural gas customers for 2013, with no rate adjustment in 2014.
- An increase of approximately $1.3 million (6.0%) for Wisconsin Electric's Downtown Milwaukee (Valley) steam utility customers for 2013 and another $1.3 million (6.0%) in 2014.
- An increase of approximately $1 million (7.0%) in 2013 and $1 million (6.0%) in 2014, respectively, for Wisconsin Electric's Milwaukee County steam utility customers.

These rate adjustments were effective January 1, 2013. In addition, the PSCW indicated that Wisconsin Electric's and Wisconsin Gas' allowed return on equity would remain at 10.4% and 10.5%, respectively. The PSCW also approved escrow accounting treatment for the energy cash grant.

2012 Wisconsin Rate Case: On May 26, 2011, Wisconsin Electric and Wisconsin Gas filed an application with the PSCW to initiate rate proceedings. In lieu of a traditional rate proceeding, we requested an alternative approach, which resulted in no increase in 2012 base rates for our customers. In order for us to proceed under this alternative approach, Wisconsin Electric and Wisconsin Gas requested that the PSCW issue an order that:

- Authorizes Wisconsin Electric to suspend the amortization of $148 million of regulatory costs during 2012, with amortization to begin again in 2013.
- Authorizes $148 million of carrying costs and depreciation on previously authorized air quality and renewable energy projects, effective January 1, 2012.
- Authorizes the refund of $26 million of net proceeds from Wisconsin Electric's settlement of the spent nuclear fuel litigation with the DOE.
- Authorizes Wisconsin Electric to reopen the rate proceeding in 2012 to address, for rates effective in 2013, all issues set aside during 2012.
- Schedules a proceeding to establish a 2012 fuel cost plan.

We received a final written order from the PSCW on November 3, 2011. For information related to the proceeding to establish a 2012 fuel cost plan, see 2012 Fuel Recovery Request below.

2012 Michigan Rate Case: On July 5, 2011, Wisconsin Electric filed a $17.5 million rate increase request with the MPSC, primarily to recover the costs of environmental upgrades and OC 2. Pursuant to Michigan law, we self-implemented a $5.7 million interim electric base rate increase in January 2012. This increase was partially offset by a refund of $2.7 million of net proceeds from Wisconsin Electric's settlement of the spent nuclear fuel litigation with the DOE, resulting in a net $3.0 million rate increase. In addition, approximately $2.0 million of renewable costs were included in our Michigan fuel recovery rate effective January 1, 2012. The MPSC approved a total increase in electric base rates of $9.2 million annually, effective June 27, 2012, and authorized a 10.1% return on equity.

2010 Wisconsin Rate Case: In March 2009, Wisconsin Electric and Wisconsin Gas initiated rate proceedings with the PSCW. In December 2009, the PSCW approved the following rate adjustments:

- An increase of approximately $85.8 million (3.35%) in retail electric rates for Wisconsin Electric, which was partially offset by bill credits in 2010;
- A decrease of approximately $2.0 million (0.35%) for natural gas service for Wisconsin Electric;
- An increase of approximately $5.7 million (0.70%) for natural gas service for Wisconsin Gas; and
- A decrease of approximately $0.4 million (1.65%) for Wisconsin Electric's Valley steam utility customers and a decrease of approximately $0.1 million (0.47%) for its Milwaukee County steam utility customers.

These rate adjustments became effective January 1, 2010. In addition, the PSCW lowered the authorized return on equity for Wisconsin Electric from 10.75% to 10.4% and for Wisconsin Gas from 10.75% to 10.5%.

As part of its final decision in the 2010 rate case, the PSCW authorized Wisconsin Electric to reopen the docket in 2010 to review updated 2011 fuel costs. In September 2010, Wisconsin Electric filed an application with the PSCW to reopen the docket to review updated 2011 fuel costs and to set rates for 2011 that reflect those costs. Wisconsin Electric requested an increase in 2011 Wisconsin retail electric rates of $38.4 million, or 1.4%, related to the increase in 2011 monitored fuel costs as compared to the level of monitored fuel costs then embedded in rates. In

December 2010, Wisconsin Electric reduced its request by approximately $5.2 million. Adjustments by the PSCW reduced the request by an additional $7.8 million. The PSCW issued its final decision, which increased annual Wisconsin retail rates by $25.4 million effective April 29, 2011. The net increase was being driven primarily by an increase in the delivered cost of coal.

2010 Michigan Rate Increase Request: In July 2009, Wisconsin Electric filed a $42 million rate increase request with the MPSC, primarily to recover the costs of PTF projects. In December 2009, the MPSC approved Wisconsin Electric's modified self-implementation plan to increase electric rates in Michigan by approximately $12 million, effective upon commercial operation of OC 1, which occurred on February 2, 2010. On July 1, 2010, the MPSC issued the final order, approving an additional increase of $11.5 million effective July 2, 2010. The combined total increase was $23.5 million annually, or 14.2%. In August 2010, our largest customers, two iron ore mines, filed an appeal with the MPSC regarding this rate order. In October 2010, the MPSC ruled on the mines' appeal and reduced the rate increase by approximately $0.3 million annually, effective November 1, 2010. In November 2010, the mines filed a Claim of Appeal of the October 2010 order with the Michigan Court of Appeals. In December 2010, the MPSC filed a Motion for Remand with the Court of Appeals. In March 2011, the Court of Appeals denied the Motion for Remand. All briefs have been filed and the case is awaiting scheduling of oral argument.

Limited Rate Adjustment Requests

2012 Fuel Recovery Request: In August 2011, Wisconsin Electric filed a $50 million rate increase request with the PSCW to recover forecasted increases in fuel and purchased power costs. The primary reasons for the increase were projected higher coal, coal transportation and purchased power costs. This filing was made under the new Wisconsin fuel rules which require annual fuel cost filings. In January 2012, the PSCW issued an order which provided for an increase in fuel costs of approximately $26 million, offset by approximately $26 million from the settlement with the DOE regarding the storage of spent nuclear fuel, resulting in no change in customer bills.

2010 Fuel Recovery Request: In February 2010, Wisconsin Electric filed a $60.5 million rate increase request with the PSCW to recover forecasted increases in fuel and purchased power costs. The increase in fuel and purchased power costs was driven primarily by increases in the price of natural gas compared to the forecasted prices included in the 2010 PSCW rate case order, changes in the timing of plant outages and increased MISO costs. Effective March 25, 2010, the PSCW approved an annual increase of $60.5 million in Wisconsin retail electric rates on an interim basis. On April 28, 2011, the PSCW approved the final increase with no changes.

Other Utility Rate Matters

Oak Creek Air Quality Control System: In July 2008, we received approval from the PSCW granting Wisconsin Electric authority to construct wet flue gas desulfurization and selective catalytic reduction facilities at Oak Creek Power Plant units 5-8. Construction of these emission controls began in late July 2008. In March 2012, the wet flue gas desulfurization and selective catalytic reduction equipment for units 5 and 6 was placed into commercial operation. In September 2012, the equipment for units 7 and 8 was placed into commercial operation. The final cost of completing this project was approximately $740 million ($900 million including AFUDC). The cost of constructing these facilities has been included in our previous estimates of the costs to implement the Consent Decree with the EPA.

Wisconsin Fuel Rules: Embedded within Wisconsin Electric's base rates is an amount to recover fuel costs. New fuel rules adopted in December 2010 require the company to defer, for subsequent rate recovery or refund, any under-collection or over-collection of fuel costs that are outside of the utility's symmetrical fuel cost tolerance, which the PSCW set at plus or minus 2% of the utility's approved fuel cost plan. Fuel cost plans approved by the PSCW after January 1, 2011 are subject to the new rules. The deferred fuel costs are subject to an excess revenues test.

Electric Transmission Cost Recovery: Wisconsin Electric divested its transmission assets with the formation of ATC in January 2001. We now procure transmission service from ATC at FERC approved tariff rates. In connection with the formation of ATC, our transmission costs have escalated due to the socialization of costs within ATC and increased transmission infrastructure requirements in the state. In 2002, in connection with the increased costs experienced by our customers, the PSCW issued an order which allowed us to use escrow accounting whereby we deferred transmission costs that exceeded amounts embedded in our rates. We were allowed to earn a return on the unrecovered transmission costs we deferred at our weighted-average cost of capital. As of December 31, 2012, we had $114.1 million of unrecovered transmission costs related to prior deferrals that are not subject to escrow accounting because our 2008 and 2010 PSCW rate orders provided for recovery of these costs. In the 2013 Wisconsin Rate Case, the PSCW reauthorized escrow accounting for future transmission costs and we are allowed to accrue these costs on a net of tax basis at the short-term debt rate.

Gas Cost Recovery Mechanism: Our natural gas operations operate under GCRMs as approved by the PSCW. Generally, the GCRMs allow for a dollar for dollar recovery of gas costs. The GCRMs use a modified one for one method that measures commodity purchase costs against a monthly benchmark which includes a 2% tolerance. Costs in excess of this monthly benchmark are subject to additional review by the PSCW before they can be passed through to our customers. The modified one for one is the same method used by the other utilities in Wisconsin.

Renewables, Efficiency and Conservation: In March 2006, Wisconsin revised the requirements for renewable energy generation by enacting Act 141. Act 141 defines "baseline renewable percentage" as the average of an energy provider's renewable energy percentage for 2001, 2002 and 2003. A utility's renewable energy percentage is equal to the amount of its total retail energy sales that are provided by renewable sources. Wisconsin Electric's baseline renewable energy percentage is 2.27%. Under Act 141, Wisconsin Electric could not decrease its renewable energy percentage for the years 2006-2009, and for the years 2010-2014, it must increase its renewable energy percentage at least two percentage points to a level of 4.27%. As of December 31, 2012, we are in compliance with the Wisconsin renewable energy percentage of 4.27%. Act 141 further requires that for the year 2015 and beyond, the renewable energy percentage must increase at least six percentage points above the baseline to a level of 8.27%. Act 141 established a goal that 10% of all electricity consumed in Wisconsin be generated by renewable resources by December 31, 2015. To comply with increasing requirements, Wisconsin Electric has constructed and contracted for several hundred megawatts of wind generation and is in the process of constructing approximately 50 MW of biomass fueled generation. With the commercial operation of the Glacier Hills Wind Park in December 2011, and assuming the biomass project is completed on schedule, we expect to be in compliance with Act 141's 2015 standard. We have entered into agreements for renewable energy credits which should allow us to remain in compliance with Act 141 through 2019. If market conditions are favorable, we may purchase more renewable energy credits. See Renewable Energy Portfolio discussion below for additional information regarding the development of renewable energy generation.

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 result in unreasonable rate increases 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. 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 may not be ordered to achieve additional energy conservation or efficiency.

Act 141 also redirects the administration of energy efficiency, conservation and renewable programs from the Wisconsin Department of Administration back to the PSCW and/or contracted third parties. In addition, Act 141 required that 1.2% of utilities' annual operating revenues be used to fund these programs in 2012. The funding required by Act 141 for 2013 is also 1.2% of annual operating revenues.

Public Act 295 enacted in Michigan requires 10% of the state's energy to come from renewables by 2015 and energy optimization (efficiency) targets up to 1% annually by 2015. Public Act 295 specifically calls for current recovery of costs incurred to meet the standards and provides for ongoing review and revision to assure the measures taken are cost-effective.

Renewable Energy Portfolio: The Blue Sky Green Field wind farm project, which has 88 turbines with an installed capacity of 145 MW, commenced commercial operation in May 2008. The Glacier Hills Wind Park, which has 90 turbines with an installed capacity of 162 MW, commenced commercial operation in December 2011. The final cost of the Glacier Hills Wind Park is approximately $347 million, excluding AFUDC.

We are constructing a biomass-fueled power plant at Domtar Corporation's Rothschild, Wisconsin paper mill site. Wood waste and wood shavings will be used to produce approximately 50 MW of renewable electricity and will also support Domtar's sustainable papermaking operations. Construction commenced in June 2011. We currently expect to invest between $245 million and $255 million, excluding AFUDC, in the plant. We are targeting completion of the facility by the end of 2013.

On December 21, 2012, we purchased Montfort from NextEra Energy Resources for $27 million. Montfort has 20 turbines with an installed capacity of 30 MW.

ELECTRIC SYSTEM RELIABILITY

We continue to upgrade our electric distribution system, including substations, transformers and lines. We had adequate capacity to meet all of our firm electric load obligations during 2012 and 2011. All of our generating plants performed as expected during the warmest periods of the summer and all power purchase commitments under firm contract were received. During this period, public appeals for conservation were not required and we did not interrupt or curtail service to non-firm customers who participate in load management programs. We expect to have adequate capacity to meet all of our firm load obligations during 2013. However, extremely hot weather, unexpected equipment failure or unavailability could require us to call upon load management procedures.

ENVIRONMENTAL MATTERS

Overview

Consistent with other companies in the energy industry, we face significant ongoing environmental compliance and remediation obligations related to current and past operations. Specific environmental issues affecting our utility and non-utility energy segments include but are not limited to current and future regulation of: (1) air emissions such as SO_2, NO_x, fine particulates, mercury and greenhouse gas emissions; (2) water discharges; (3) disposal of coal combustion by-products such as fly ash; and (4) remediation of impacted properties, including former manufactured gas plant sites.

We are continuing to pursue a proactive strategy to manage our environmental compliance obligations, including: (1) developing additional sources of renewable electric energy supply; (2) reviewing water quality matters such as discharge limits and cooling water requirements and implementing improvements to our cooling water intake systems as needed; (3) adding emission control equipment to existing facilities to comply with new ambient air quality standards and federal clean air rules; (4) implementing a Consent Decree with the EPA to reduce emissions of SO_2 and NO_x by more than 65% by 2013; (5) converting the fuel source for VAPP from coal to natural gas; (6)continuing the beneficial use of ash and other solid products from coal-fired generating units; and (7) conducting the clean-up of former manufactured gas plant sites.

Air Quality

EPA Consent Decree: In April 2003, Wisconsin Electric reached a Consent Decree with the EPA, in which it agreed to significantly reduce air emissions from certain of its coal-fired generating facilities. The U.S. District Court for the Eastern District of Wisconsin approved the amended Consent Decree and entered it in October 2007. For further information, see Note P -- Commitments and Contingencies in the Notes to Consolidated Financial Statements.

National Ambient Air Quality Standards (NAAQS)

8-hour Ozone Standards: In April 2004, the EPA designated 10 counties in southeastern Wisconsin as non-attainment areas for the 1997 8-hour ozone ambient air quality standard. The EPA has since redesignated all of these counties to attainment. In 2008, the EPA issued an additional, more stringent 8-hour ozone standard, and made final attainment designations for this revised standard in 2012. In April 2012 and May 2012, the EPA designated Sheboygan County and the eastern portion of Kenosha County, respectively, as 2008 8-hour ozone standard non-attainment areas. The net result of all of these actions is that construction permitting for all of our Wisconsin power plants, except the Pleasant Prairie Power Plant, is expected to be subject to less stringent permitting requirements. In addition, modifications to these facilities should no longer be required to obtain emission offsets. The Pleasant Prairie Power Plant will continue to be subject to more stringent permitting requirements and offset provisions.

In January 2010, the EPA announced its decision to further lower the 2008 8-hour ozone standard. However, in September 2011, President Obama requested the EPA to delay the reconsideration of the 8-hour ozone standard until 2013.

Fine Particulate Standard: In 2009, the EPA designated three counties in southeast Wisconsin (Milwaukee, Waukesha and Racine) as not meeting the daily standard for $PM_{2.5}$. In April 2012, the EPA proposed to determine that these three counties meet the $PM_{2.5}$ standard, and proposed to suspend the requirement that the state submit a State Implementation Plan (SIP) including reasonably available control technology (RACT) regulations. On December 28, 2012, the EPA re-proposed this determination along with further clarification of its authority to suspend RACT and other SIP requirements. Until the EPA finalizes this action and redesignates the three counties to attainment, our generating facilities in the non-attainment counties will continue to be subject to more stringent construction permitting requirements and emission offset provisions. On December 14, 2012, the EPA issued a revised and more stringent annual $PM_{2.5}$ standard. Current monitored air quality data indicates that all areas of

Wisconsin and Michigan's Upper Peninsula meet the revised standard. Although we do not expect the lower standard to impose any additional requirements on our operations, until the EPA develops a rule or guidance that dictates implementation of the new standard, we are unable to predict how these actions may affect any future construction permitting activities.

Sulfur Dioxide Standard: In June 2010, the EPA issued new hourly SO_2 NAAQS that became effective in August 2010. These standards, as modified, represent a significant change from the previous SO_2 standards. The implementation guidance for the new standards, among other things, required attainment designations to be based on modeling rather than monitoring. Traditionally, attainment designations were based on monitored data. The EPA has since withdrawn this implementation guidance, and has indicated it is going to propose new implementation guidance through a rulemaking in 2013.

Various parties have submitted judicial and administrative challenges to this rule, and litigation is pending in the U.S. Court of Appeals for the D.C. Circuit challenging, among other things, the stringency of the standards and the EPA's plans to require attainment designations to be based on modeling.

If the new standards remain in place, we believe that we would not need to make significant capital expenditures at the majority of our generation units because of prior investments in pollution control equipment and technology. However, we believe that the new standards will require us to retrofit PIPP in the Upper Peninsula of Michigan with additional environmental controls. In November 2012, we entered into a joint ownership agreement with Wolverine whereby Wolverine will pay for the installation of air quality control systems at PIPP and will receive a minority ownership interest in the plant in return. This transaction is subject to the receipt of regulatory approvals from various state and federal regulatory agencies, including the MPSC, PSCW and FERC. We began submitting applications for these regulatory approvals in February 2013.

The new standards may also require us to make modifications at some of our smaller generation units.

Nitrogen Dioxide Standard: In January 2010, the EPA announced a new hourly Nitrogen Dioxide standard, which became effective in April 2010. We are unable to predict the impact on the operation of our generation facilities until final attainment designations are made and until any potential additional rules are adopted.

Mercury and Other Hazardous Air Pollutants: In December 2011, the EPA issued the final MATS rule, which imposes stringent limitations on numerous hazardous air pollutants, including mercury, from coal and oil-fired electric generating units. While we are continuing to evaluate the impact of the rule on the operation of our existing coal-fired generation facilities, as well as alternatives for complying with the rule, we currently estimate our capital cost to comply with this rule will be approximately \$8.0 million to \$12.5 million. Based upon our review of the rules and plans to convert the VAPP from coal to natural gas fuel, we currently anticipate that only the PIPP will require modifications, which we expect will be funded by Wolverine under the joint ownership agreement. We believe that our clean air strategy, including the environmental upgrades that have been constructed and that are currently under construction at our other coal-fired plants, positions those other plants well to meet the rule's requirements.

Cross-State Air Pollution Rule: In August 2011, the EPA issued the CSAPR, formerly known as the Clean Air Transport Rule. This rule was proposed in 2010 to replace the Clean Air Interstate Rule (CAIR), which had been remanded to the EPA in 2008. The stated purpose of the CSAPR is to limit the interstate transport of emissions of NO_x and SO_2 that contribute to fine particulate matter and ozone non-attainment in downwind states through a proposed allocation scheme. In February 2012, the EPA issued final technical revisions to the rule and issued a draft final rule which together delay the implementation date for certain penalty provisions that could potentially impact the PIPP and increase the number of allowances issued to the states of Michigan and Wisconsin. Even with these proposed revisions, however, the PIPP may not have been allocated sufficient allowances to meet its obligations to operate and provide stability to the transmission system in the Upper Peninsula of Michigan. This situation could then put the plant at risk for certain penalties under the rule.

The rule was scheduled to become effective January 1, 2012. However, we and a number of other parties sought judicial review of the rule, and in August 2012, the U.S. Court of Appeals for the District of Columbia Circuit vacated the CSAPR, keeping the CAIR in effect. The EPA had requested the court to re-hear the case; however, on January 24, 2013, the court denied the EPA's request. The EPA has 90 days from the date of the D.C. Circuit Court's decision to appeal to the United States Supreme Court.

Wisconsin and Michigan Mercury Rules: Both Wisconsin and Michigan have mercury rules that require a 90% reduction of mercury. We have plans in place to comply with those requirements and the costs of these plans are incorporated in our capital and operation and maintenance costs.

Clean Air Visibility Rule: The EPA issued the Clean Air Visibility Rule in June 2005 to address Regional Haze, or regionally-impaired visibility caused by multiple sources over a wide area. The rule defines Best Available Retrofit Technology (BART) requirements for electric generating units and how BART will be addressed in the 28 states subject to the EPA's CAIR. The pollutants from power plants that reduce visibility include $PM_{2.5}$ or compounds that contribute to fine particulate formation, NO_x, SO_2 and ammonia.

In June 2012, the EPA promulgated a Federal Implementation Plan that approves reliance on the CSAPR to satisfy electric generating unit BART requirements for NO_x and SO_2. In December 2012, the EPA approved the remainder of Michigan's regional haze SIP.
In August 2012, the EPA approved Wisconsin's regional haze SIP, which also relies on the CSAPR to satisfy electric generating unit BART requirements for NO_x and SO_2.

Because of the court decision to vacate CSAPR and potential continuing litigation on that decision, we will not be able to determine final regional haze requirements for NO_x and SO_2 at our facilities until judicial review of CSAPR is completed and any subsequent rulemaking activities required as a result of that review have been finalized.

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

- Repowering the Port Washington Power Plant from coal to natural gas-fired combined cycle units.
- Adding coal-fired units as part of the Oak Creek expansion that are the most thermally efficient coal units in our system.
- Increasing investment in energy efficiency and conservation.
- Adding renewable capacity and continuing to offer the Energy for Tomorrow® renewable energy program.
- Planning to convert the fuel source at the VAPP from coal to natural gas.
- Retirement of coal units 1-4 at the Presque Isle Power Plant.

Federal, state, regional and international authorities have undertaken efforts to limit greenhouse gas emissions. The President's administration recently reaffirmed that regulation of greenhouse gas emissions continues to be a top priority. Although legislation that would impose mandatory requirements related to greenhouse gas emissions, renewable energy standards and/or energy efficiency standards failed to pass in the U.S. Congress, we expect such legislation to be considered in the future. Any mandatory restrictions on our CO_2 emissions that may be adopted by Congress or Wisconsin's or Michigan's legislature could result in significant compliance costs that could affect future results of operations, cash flows and financial condition.

While climate change legislation has yet to be adopted, the EPA is pursuing regulation of greenhouse gas emissions using its existing authority under the CAA. In March 2012, the EPA proposed new source performance standards pertaining to greenhouse gas emissions from certain new power plants, including coal-fired plants, based on the performance of combined cycle natural gas-fueled generating plants.

We expect the EPA to attempt to address performance standards for existing generating units in 2013. Any such regulations may impact how we operate our existing facilities. Depending on the extent of rate recovery and other factors, these anticipated future rules could have a material adverse impact on our financial condition. For additional information, see the caption "We may face significant costs to comply with the regulation of greenhouse gas emissions." under Item 1A Risk Factors in this report.

We are required to report our CO_2 equivalent emissions from our electric generating facilities to the EPA under its Mandatory Reporting of Greenhouse Gases rule. For 2011, we reported CO_2 equivalent emissions of approximately 22.4 million metric tonnes to the EPA, compared with approximately 20.9 million metric tonnes for 2010. Based upon our preliminary analysis of the monitoring data, we estimate that we will report CO_2 equivalent emissions of approximately 18.1 million metric tonnes to the EPA for 2012. The level of CO_2 and other greenhouse gas emissions vary from year to year and are dependent on the level of electric generation and mix of fuel sources, which is determined primarily by demand, the availability of the generating units, the unit cost of fuel consumed and how our units are dispatched by MISO.

We are also required to report CO_2 amounts related to the natural gas our gas utility distributes and sells. For 2011, we reported approximately 9.5 million metric tonnes of CO_2 to the EPA related to our distribution and sale of natural gas, compared with approximately 9.0 million metric tonnes for 2010. Based upon our preliminary analysis of the monitoring data, we estimate that we will report CO_2 emissions of approximately 8.4 million metric tonnes to the EPA for 2012.

Valley Power Plant Conversion: In August 2012, we announced plans to convert the fuel source for VAPP from coal to natural gas. We currently expect the cost of this conversion to be between $60 million and $65 million and, subject to receipt of PSCW approval and a construction air permit from the WDNR, anticipate that the conversion will be completed by the end of 2015 or early 2016. We expect to file for a Certificate of Authority from the PSCW during the second quarter of 2013.

In June 2012, we received approval from the PSCW to replace and upgrade the Lincoln Arthur natural gas main, which has the capability to accommodate the increased natural gas required for the conversion of VAPP to natural gas. For further information, see Note P -- Commitments and Contingencies in the Notes to Consolidated Financial Statements.

Water Quality

Clean Water Act: Section 316(b) of the Clean Water Act requires that the location, design, construction and capacity of cooling water intake structures reflect the Best Technology Available (BTA) for minimizing adverse environmental impacts. The EPA finalized rules for new facilities (Phase I) in 2001. Final rules for cooling water intake systems at existing facilities (Phase II) were promulgated in 2004. However, as a result of litigation, the EPA withdrew the Phase II rule in July 2007 and advised states to use their best professional judgment in making BTA decisions while the rule remains suspended.

The EPA proposed a new Phase II rule in 2011, which must be finalized by June 27, 2013. Once the rule is final, it will apply to all of our existing generating facilities with cooling water intake structures other than the Oak Creek expansion, which was permitted under the Phase I rules.

The proposed rule would create an impingement mortality reduction standard for all existing facilities. One proposed approach would allow a facility owner to satisfy the BTA requirement with respect to impingement mortality reduction if it demonstrates that its cooling water intake system has a maximum intake velocity of no more than 0.5 feet per second. Oak Creek Power Plant Units 5-8, Pleasant Prairie and Port Washington Generating Station all employ technologies that have a cooling water intake withdrawal velocity of less than 0.5 feet per second. We are still evaluating impingement mortality reduction compliance options for the PIPP and VAPP.

The EPA has proposed that the BTA for entrainment mortality reduction be determined on a case-by-case basis. Therefore, permitting agencies would be required to determine BTA with respect to entrainment on a site-specific basis taking into consideration several factors. Because the entrainment reduction standard is a site-specific determination, we cannot yet determine what, if any, intake structure or operational modifications will be required to meet this proposed requirement.

Depending on the final requirements of the Phase II rule, we may need to modify the cooling water intake systems at some of our facilities. However, we are not able to make a determination until after the Phase II rule is final.

On December 27, 2012, the WDNR issued a new Wisconsin Pollutant Discharge Elimination System (WPDES) permit for VAPP that became effective on January 1, 2013. The new permit includes significant new immediate and long-term permit requirements. Effluent toxicity testing and monitoring for additional parameters (phosphorous, mercury and ammonia-nitrogen), and a new heat addition limit from the cooling water discharges all took effect immediately. Longer term compliance requirements include thermal discharge studies, phosphorous evaluation and feasibility for reduction, mercury minimization planning, and redesign of the cooling water intakes to minimize impingement impacts to aquatic organisms.

Steam Electric Effluent Guidelines: These federal guidelines regulate waste water discharges from our power plant processes, and are under review by the EPA. The EPA rules are currently expected to be proposed by the end of April 2013, and finalized by the end of May 2014. After the promulgation of final rules, it is expected that the WDNR will need to modify Wisconsin's rules. The existing Wisconsin state rules for waste water discharge are very stringent, and therefore, the systems that have been installed at the Pleasant Prairie Power Plant and the Oak Creek Power Plant use advanced technology. We are unable to determine the impact, if any, of these rules on our facilities at this time.

Land Quality

Proposed New Coal Combustion Products Regulation: We currently have a program of beneficial utilization for substantially all of our coal combustion products, including fly ash, bottom ash and gypsum, which minimizes the need for disposal in specially-designed landfills. Both Wisconsin and Michigan have regulations governing the use and disposal of these materials. In 2010, the EPA issued draft rules for public comment proposing two alternative rules for regulating coal combustion products, one of which would classify the materials as hazardous waste. We anticipate the earliest the EPA will take action on a final rule is the first quarter of 2014. If coal combustion products are classified as hazardous waste, it could have a material adverse effect on our ability to continue our current program.

If coal combustion products are classified as hazardous waste and we terminate our coal combustion products utilization program, we could be required to dispose of the coal combustion products at a significant cost to the Company, which could adversely impact our results of operations and financial condition.

In addition, the EPA finalized the Commercial and Industrial Solid Waste Incineration Units rule under the CAA, as well as the Non-Hazardous Secondary Materials Rule. We are continuing to pursue an EPA determination on acceptable use for coal ash as a non-hazardous secondary material based on our processing of the materials prior to reburning as currently allowed under the Secondary Materials Rule. Both of these rules have the potential to negatively affect our ability to reburn coal ash from power plants and landfills.

Manufactured Gas Plant Sites: We continue to voluntarily review and address environmental conditions at a number of former manufactured gas plant sites. For further information, see Note P -- 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 P -- Commitments and Contingencies in the Notes to Consolidated Financial Statements.

LEGAL MATTERS

Cash Balance Pension Plan: See Note P -- Commitments and Contingencies in the Notes to Consolidated Financial Statements for information regarding a lawsuit filed against the Plan.

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.

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

NUCLEAR OPERATIONS

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

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

In August 2000, the United States Court of Appeals for the D.C. 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 in November 2000 against the DOE in the Court of Federal Claims. In October 2004, the Court of Federal Claims granted Wisconsin Electric's motion for summary judgment on liability. The Court held a trial during September and October 2007 to determine damages. In December 2009, the Court ruled in favor of Wisconsin Electric, granting us more than $50 million in damages. In February 2010, the DOE filed an appeal. We negotiated a settlement with the DOE for $45.5 million, which we received in the first quarter of 2011. This amount, net of costs incurred, was returned to customers as part of the PSCW's approval of our 2012 fuel recovery request and the MPSC's approval of our interim order for the 2012 Michigan rate case.

INDUSTRY RESTRUCTURING AND COMPETITION

Electric Utility Industry

The regulated energy industry continues to experience significant changes. FERC continues to support large RTOs, which affect the structure of the wholesale market. To this end, the MISO implemented bid-based markets, the MISO Energy Markets, including the use of LMP to value electric transmission congestion and losses. The MISO Energy Markets commenced operation in April 2005 for energy distribution and in January 2009 for operating reserves. 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, if at all, in Wisconsin; however, Michigan has adopted retail choice which potentially affects our Michigan operations.

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 on electric reliability infrastructure issues for the state of Wisconsin in recent years.

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

Competition and customer switching to alternative suppliers in our service territories in Michigan has been limited. However, the additional competitive pressures resulting from retail access could lead to a loss of customers and our incurring stranded costs. A loss of customers could also have a material adverse effect on our results of operations and cash flows.

Electric Transmission and Energy Markets

In connection with its status as a FERC approved RTO, MISO developed bid-based energy markets, which were implemented on April 1, 2005. In January 2009, MISO commenced the Energy and Operating Reserves Markets, which includes the bid-based energy markets and an ancillary services market. We previously self-provided both regulation reserves and contingency reserves. In the MISO ancillary services market, we buy/sell regulation and contingency reserves from/to the market. The MISO ancillary services market has been able to reduce overall ancillary services costs in the MISO footprint. The MISO ancillary services market has enabled MISO to assume significant balancing area responsibilities such as frequency control and disturbance control.

In MISO, base transmission costs are currently being paid by Load Serving Entities located in the service territories of each MISO transmission owner. FERC has previously confirmed the use of the current transmission cost allocation methodology. Certain additional costs for new transmission projects are allocated throughout the MISO footprint.

We, along with others, have sought rehearing and/or appeal of the FERC's various Revenue Sufficiency Guarantee orders related to the determination that MISO had applied its energy markets tariff correctly in the assessment of the charges. The net effects of any final determination by FERC or the courts are uncertain at this time.

As part of MISO, a market-based platform was developed for valuing transmission congestion 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 Auction Revenue Rights (ARRs) and Financial Transmission Rights (FTRs). ARRs are allocated to market participants by MISO and FTRs are purchased through auctions. A new allocation and auction were completed for the period of June 1, 2012 through May 31, 2013. The resulting ARR valuation and the secured FTRs are expected to mitigate our transmission congestion risk for that period.

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 continues to be on hold. Currently, we are unable to predict the impact of potential future deregulation on our results of operations or financial position.

OTHER MATTERS

Oak Creek Expansion Fuel Flexibility Project: The Oak Creek expansion units were designed and permitted to use bituminous coal from the Eastern United States. Market forces have resulted in a significant price differential between bituminous and sub-bituminous coals. We recently received a new air construction permit from the WDNR to modify the Oak Creek expansion units for potential future use of sub-bituminous coal. We are scheduled to begin testing sub-bituminous coal in various combinations with bituminous coal in 2013 to identify any equipment limitations that should be considered prior to filing with the PSCW for a Certificate of Authority to make the fuel flexibility modifications. In February 2013, the Sierra Club and the Midwest Environmental Defense Center filed for a contested case hearing with the WDNR to challenge the issuance of the air construction permit.

Paris Generating Station Units 1 and 4 Temporary Outage: Between 2000 and 2002, we replaced the blades on the four PSGS combustion turbine generators with blades that were approximately 7% more efficient. Although the work was performed as routine maintenance that we did not believe required a construction permit at the time and the plant has not been operated to use the potential additional capacity, the WDNR has indicated that it now considers this maintenance to be a modification requiring a construction permit. The WDNR issued a NOV to Wisconsin Electric on January 7, 2013 alleging violations of the new source review rules and certain Wisconsin environmental rules. At the same time, the WDNR also issued an administrative order that prohibits us from operating PSGS Units 1 and 4 until the earlier of: (1) Units 1 and 4 achieve the applicable NO_x emission rates; (2) the Wisconsin regulations are revised so that Units 1 and 4 can achieve the emission limits or are no longer subject to the limits; (3) the alleged modification is resolved through a consent decree; or (4) until a court decides that the blade replacement project was not a major modification. We are presently evaluating alternative approaches to return these peaking units to service, and expect that Units 1 and 4 will remain out of service until at least 2014. In addition, we may be subject to fines and penalties. In February 2013, the Sierra Club filed for a contested case hearing with the WDNR in connection with the administrative order.

We continue to evaluate the impact, if any, that this outage may have on network reliability, and to determine whether we will need to find alternative sources of generation in the short-term to replace the generation from these units during the temporary outage.

PSGS Units 2 and 3 remain available for operation, because the turbine blade maintenance on these units occurred prior to a rule change in 2001.

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.

Section 1603 Renewable Energy Treasury Grant: We expect to receive a treasury grant of approximately $72 million related to the construction of our biomass facility in Rothschild, Wisconsin. We expect to recognize the treasury grant when the plant is placed into service, which is when we expect to conclude it is probable we will receive the grant and when we can reasonably estimate the grant amount. The expected receipt of the treasury grant has been taken into consideration by the PSCW in connection with our electric rates that became effective January 1, 2013. Our Wisconsin retail electric customers will receive bill credits in 2013 and 2014 related to the treasury grant. When we recognize the treasury grant as income, we will also defer a portion of the grant associated with the future bill credits and the deferred grant will be amortized to income to match the bill credits to the customers.

International Financial Reporting Standards: During 2009, the SEC announced a "roadmap" for the potential use by U.S. registrants of IFRS instead of GAAP. The SEC issued a Work Plan to consider specific areas and factors relevant to a determination of whether, when and how the current financial reporting system for U.S. registrants should be transitioned to a system incorporating IFRS. In July 2012, the SEC Staff issued its final report on the Work Plan. The report does not include a final policy or decision as to whether IFRS might be incorporated into the financial reporting system for U.S. registrants, or how such incorporation should occur. The Staff report indicates that additional analysis is necessary before any SEC decision is made about incorporating IFRS into the U.S. financial reporting system. The timing of this additional activity is currently unknown. To the extent the SEC determines to adopt IFRS, if at all, we are currently unable to determine when we would be required to begin using IFRS.

CRITICAL ACCOUNTING ESTIMATES

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

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

Regulatory Accounting: Our utility subsidiaries operate under rates established by state and federal regulatory commissions which are designed to recover the cost of service and provide a reasonable return to investors. The actions of our regulators may allow us to defer costs that non-regulated entities would expense and accrue liabilities that non-regulated companies would not. As of December 31, 2012, we had $1,380.3 million in regulatory assets and $868.3 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 regulatory accounting. In this situation, we would record the regulatory assets related to unrecognized pension and OPEB costs as a reduction of equity, after tax. The balance of our regulatory assets net of regulatory liabilities would be recorded as an extraordinary after-tax non-cash charge to earnings. We continually review the applicability of regulatory accounting and have determined that it is currently appropriate to continue following it. In addition, each quarter we perform a review of our regulatory assets and our regulatory environment and we evaluate whether we believe that it is probable that we will recover the regulatory assets in future rates. See Note C -- Regulatory Assets and Liabilities in the Notes to Consolidated Financial Statements for additional information.

Pension and OPEB: Our reported costs of providing non-contributory defined pension benefits (described in Note M -- 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.

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

Pension Plan Actuarial Assumption	Impact on Annual Cost (Millions of Dollars)
0.5% decrease in discount rate and lump sum conversion rate	$4.8
0.5% decrease in expected rate of return on plan assets	$6.2

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

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

OPEB Plan Actuarial Assumption	Impact on Annual Cost (Millions of Dollars)
0.5% decrease in discount rate	$2.5
0.5% decrease in health care cost trend rate in all future years	$(3.3)
0.5% decrease in expected rate of return on plan assets	$1.3

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 2012 of approximately $4.2 billion included accrued utility revenues of $278.1 million as of December 31, 2012.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See Management's Discussion and Analysis of Financial Condition and Results of Operations - Factors Affecting Results, Liquidity and Capital Resources -- Market Risks and Other Significant Risks in Item 7 of this report, as well as Note K -- Derivative Instruments and Note L -- Fair Value Measurements in the Notes to Consolidated Financial Statements, for information concerning potential market risks to which Wisconsin Energy and its subsidiaries are exposed.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

WISCONSIN ENERGY CORPORATION
CONSOLIDATED INCOME STATEMENTS
Year Ended December 31

	2012	2011	2010
	(Millions of Dollars, Except Per Share Amounts)		
Operating Revenues	$4,246.4	$4,486.4	$4,202.5
Operating Expenses			
Fuel and purchased power	1,098.6	1,169.7	1,099.9
Cost of gas sold	545.8	728.7	751.5
Other operation and maintenance	1,116.1	1,256.8	1,327.5
Depreciation and amortization	364.2	330.2	305.6
Property and revenue taxes	121.4	113.7	106.0
Total Operating Expenses	3,246.1	3,599.1	3,590.5
Amortization of Gain	—	—	198.4
Operating Income	1,000.3	887.3	810.4
Equity in Earnings of Transmission Affiliate	65.7	62.5	60.1
Other Income and Deductions, net	34.8	62.7	40.2
Interest Expense, net	248.2	235.8	206.4
Income from Continuing Operations Before Income Taxes	852.6	776.7	704.3
Income Tax Expense	306.3	263.9	249.9
Income from Continuing Operations	546.3	512.8	454.4
Income from Discontinued Operations, Net of Tax	—	13.4	2.1
Net Income	$546.3	$526.2	$456.5
Earnings Per Share (Basic)			
Continuing Operations	$2.37	$2.20	$1.94
Discontinued Operations	—	0.06	0.01
Total Earnings Per Share (Basic)	$2.37	$2.26	$1.95
Earnings Per Share (Diluted)			
Continuing Operations	$2.35	$2.18	$1.92
Discontinued Operations	—	0.06	0.01
Total Earnings Per Share (Diluted)	$2.35	$2.24	$1.93
Weighted Average Common Shares Outstanding (Millions)			

Basic	230.2	232.6	233.8
Diluted	232.8	235.4	236.7

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

WISCONSIN ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS
December 31

ASSETS

	2012	2011
	(Millions of Dollars)	
Property, Plant and Equipment		
In service	$14,238.8	$12,977.7
Accumulated depreciation	(4,036.0)	(3,797.8)
	10,202.8	9,179.9
Construction work in progress	315.9	921.3
Leased facilities, net	53.5	59.2
Net Property, Plant and Equipment	10,572.2	10,160.4
Investments		
Equity investment in transmission affiliate	378.3	349.7
Other	35.5	43.6
Total Investments	413.8	393.3
Current Assets		
Cash and cash equivalents	35.6	14.1
Restricted cash	2.7	45.5
Accounts receivable, net of allowance for doubtful accounts of $58.0 and $61.7	285.3	349.4
Income taxes receivable	98.1	155.1
Accrued revenues	278.1	252.7
Materials, supplies and inventories	360.7	382.0
Prepayments	145.5	140.3
Other	107.9	87.1
Total Current Assets	1,313.9	1,426.2
Deferred Charges and Other Assets		
Regulatory assets	1,339.0	1,238.7
Goodwill	441.9	441.9
Other	204.2	201.6
Total Deferred Charges and Other Assets	1,985.1	1,882.2
Total Assets	$14,285.0	$13,862.1

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

WISCONSIN ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS
December 31

CAPITALIZATION AND LIABILITIES

	2012	2011
	(Millions of Dollars)	
Capitalization		
Common equity	$4,135.1	$3,963.3
Preferred stock of subsidiary	30.4	30.4
Long-term debt	4,453.8	4,614.3
Total Capitalization	8,619.3	8,608.0
Current Liabilities		
Long-term debt due currently	412.1	32.6
Short-term debt	394.6	669.9
Accounts payable	368.4	325.7
Accrued payroll and benefits	100.9	105.9
Other	167.3	230.4
Total Current Liabilities	1,443.3	1,364.5
Deferred Credits and Other Liabilities		
Regulatory liabilities	866.5	902.0
Deferred income taxes - long-term	2,117.0	1,696.1
Deferred revenue, net	709.7	754.5
Pension and other benefit obligations	244.0	222.7
Other long-term liabilities	285.2	314.3
Total Deferred Credits and Other Liabilities	4,222.4	3,889.6
Commitments and Contingencies (Note P)		
Total Capitalization and Liabilities	$14,285.0	$13,862.1

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

WISCONSIN ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS
Year Ended December 31

	2012	2011	2010
	(Millions of Dollars)		
Operating Activities			
Net income	$546.3	$526.2	$456.5
Reconciliation to cash			
Depreciation and amortization	371.7	336.4	317.4
Amortization of gain	—	—	(198.4)
Deferred income taxes and investment tax credits, net	352.2	430.6	104.9
Deferred revenue	—	3.5	100.8
Contributions to qualified benefit plans	(100.0)	(277.4)	—
Change in - Accounts receivable and accrued revenues	38.3	30.1	(50.4)
Inventories	21.3	(2.9)	(1.0)
Other current assets	12.1	(20.5)	14.1
Accounts payable	43.8	11.8	21.3
Accrued income taxes, net	57.9	(87.4)	(42.7)
Deferred costs, net	9.2	25.9	25.9
Other current liabilities	(14.9)	44.1	22.0
Other, net	(164.0)	(27.0)	40.0
Cash Provided by Operating Activities	1,173.9	993.4	810.4
Investing Activities			
Capital expenditures	(707.0)	(830.8)	(798.2)
Investment in transmission affiliate	(15.7)	(6.6)	(5.2)
Proceeds from asset sales	8.7	41.5	68.7
Change in restricted cash	42.8	(37.2)	186.2
Other, net	(58.4)	(59.4)	(85.0)
Cash Used in Investing Activities	(729.6)	(892.5)	(633.5)
Financing Activities			
Exercise of stock options	49.8	54.4	90.9
Purchase of common stock	(153.2)	(193.9)	(156.6)
Dividends paid on common stock	(276.3)	(242.0)	(187.0)
Issuance of long-term debt	251.8	720.0	530.0
Retirement and repurchase of long-term debt	(20.3)	(466.6)	(291.7)
Change in short-term debt	(275.3)	12.0	(167.2)
Other, net	0.7	4.8	9.0
Cash Used in Financing Activities	(422.8)	(111.3)	(172.6)
Change in Cash and Cash Equivalents	21.5	(10.4)	4.3
Cash and Cash Equivalents at Beginning of Year	14.1	24.5	20.2
Cash and Cash Equivalents at End of Year	$35.6	$14.1	$24.5

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

WISCONSIN ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF COMMON EQUITY

	Common Stock	Other Paid In Capital	Retained Earnings	Total
	(Millions of Dollars)			
Balance - December 31, 2009	$2.3	$755.8	$2,808.8	$3,566.9
Net income			456.5	456.5
Common stock cash dividends of $0.80 per share			(187.0)	(187.0)
Exercise of stock options		90.9		90.9
Purchase of common stock		(156.6)		(156.6)
Tax benefit from share based compensation		21.9		21.9
Stock-based compensation and other		9.5		9.5
Balance - December 31, 2010	2.3	721.5	3,078.3	3,802.1
Net income			526.2	526.2
Common stock cash dividends of $1.04 per share			(242.0)	(242.0)
Exercise of stock options		54.4		54.4
Purchase of common stock		(193.9)		(193.9)
Tax benefit from share based compensation		11.9		11.9
Stock-based compensation and other		4.6		4.6
Balance - December 31, 2011	2.3	598.5	3,362.5	3,963.3
Net income			546.3	546.3
Common stock cash dividends of $1.20 per share			(276.3)	(276.3)
Exercise of stock options		49.8		49.8
Purchase of common stock		(153.2)		(153.2)
Stock-based compensation and other		5.2		5.2
Balance - December 31, 2012	$2.3	$500.3	$3,632.5	$4,135.1

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

WISCONSIN ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CAPITALIZATION
December 31

		2012	2011
		(Millions of Dollars)	
Common Equity (see accompanying statement)		$4,135.1	$3,963.3
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)	4.50% due 2013	300.0	300.0
	6.60% due 2013	45.0	45.0
	6.00% due 2014	300.0	300.0
	5.20% due 2015	125.0	125.0
	6.25% due 2015	250.0	250.0
	4.25% due 2019	250.0	250.0
	2.95% due 2021	300.0	300.0
	6-1/2% due 2028	150.0	150.0
	5.625% due 2033	335.0	335.0
	5.90% due 2035	90.0	90.0
	5.70% due 2036	300.0	300.0
	3.65% due 2042	250.0	—
	6-7/8% due 2095	100.0	100.0
Notes (secured, nonrecourse)	4.81% effective rate due 2030	2.0	2.0
	4.91% due 2012-2030	126.7	131.2
	5.209% due 2012-2030	238.6	245.4
	4.673% due 2012-2031	196.7	202.3
	6.00% due 2012-2033	142.1	145.5
	6.09% due 2030-2040	275.0	275.0
	5.848% due 2031-2041	215.0	215.0
	6.00% due 2021	1.8	—
Notes (unsecured)	6.51% due 2013	30.0	30.0
	6.94% due 2028	50.0	50.0
	0.504% variable rate due 2016 (a)	67.0	67.0
	0.504% variable rate due 2030 (a)	80.0	80.0

	Variable rate notes held by Wisconsin Electric	(147.0)	(147.0)
	6.20% due 2033	200.0	200.0
Junior Notes (unsecured)	6.25% due 2067	500.0	500.0
Obligations under capital leases		120.0	132.4
Unamortized discount, net and other		(27.0)	(26.9)
Long-term debt due currently		(412.1)	(32.6)
Total Long-Term Debt		4,453.8	4,614.3
Total Capitalization		$8,619.3	$8,608.0

(a) Variable interest rate as of December 31, 2012.

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

WISCONSIN ENERGY CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

A -- SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

- Utility Energy Segment -- Consisting of Wisconsin Electric and Wisconsin Gas, 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 includes Wispark, which develops and invests in real estate. We have also eliminated all intercompany transactions 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: Certain prior period amounts have been reclassified on a basis consistent with the current period financial statement presentation.

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

Our retail electric rates in Wisconsin are established by the PSCW and include base amounts for fuel and purchased power costs. Beginning in January 2011, the electric fuel rules in Wisconsin allow us to defer, for subsequent rate recovery or refund, any under-collection or over-collection of fuel costs that are outside of the symmetrical fuel cost tolerance, which the PSCW set at plus or minus 2% of the approved fuel cost plan. The deferred under-collected amounts are subject to an excess revenues test.

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

For our We Power assets, we recognize revenues (consisting of the lease payments included in rates and the amortization of the deferred revenue) on a levelized basis over the term of the lease. We depreciate the PTF assets over their estimated useful life.

Accounting for MISO Energy Transactions: The MISO Energy Markets operate under both day-ahead and real-time markets. We record energy transactions in the MISO Energy Markets on a net basis for each hour.

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

Other Income and Deductions, net	2012	2011	2010
	(Millions of Dollars)		
AFUDC - Equity	$35.3	$59.4	$32.5
Gain on Property Sales	2.7	2.4	4.4
Other, net	(3.2)	0.9	3.3
Total Other Income and Deductions, net	$34.8	$62.7	$40.2

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 recorded the following property in service by segment as of December 31:

Property In Service	2012	2011
	(Millions of Dollars)	
Utility Energy	$11,080.9	$9,817.7
Non-Utility Energy	3,068.5	3,067.5
Other	89.4	92.5
Total	$14,238.8	$12,977.7

Our utility depreciation rates are certified by the PSCW and MPSC and include estimates for salvage value and removal costs. Depreciation as a percent of average depreciable utility plant was 2.9% in 2012 and 2.8% in 2011 and 2010.

Our We Power assets are being depreciated over the estimated useful life of the various property components. The components have useful lives of between 10 to 45 years for PWGS 1 and PWGS 2, and 10 to 55 years for OC 1 and OC 2.

Our regulated utilities collect in their rates amounts representing future removal costs for many assets that do not have an associated Asset Retirement Obligation (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 $725.0 million as of December 31, 2012 and $728.2 million as of December 31, 2011.

We recorded the following Construction Work in Progress (CWIP) by segment as of December 31:

CWIP	2012	2011
	(Millions of Dollars)	
Utility Energy	$298.2	$910.3
Non-Utility Energy	13.3	8.9
Other	4.4	2.1
Total	$315.9	$921.3

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

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

	2012	2011	2010
	(Millions of Dollars)		
AFUDC - Debt	$14.7	$24.7	$13.5
AFUDC - Equity	$35.3	$59.4	$32.5

Capitalized Interest and Carrying Costs - Non-Regulated Energy: As part of the construction of the PTF electric generating units, we capitalized interest during construction. As allowed under the lease agreements, we were able to collect the carrying costs during the construction of the PTF generating units from our utility customers. The carrying costs that we collected during construction have been recorded as deferred revenue on our balance sheet and we are amortizing the deferred carrying costs to revenue over the individual lease terms.

Earnings per Common Share: We compute basic earnings per common share by dividing our net income attributed to common shareholders by the weighted-average number of common shares outstanding during the period. Diluted earnings per common share is computed by dividing net income attributed to common shareholders by the weighted average number of common shares outstanding during the period, adjusted for the exercise and/or conversion of all potentially dilutive securities. Such dilutive securities include in-the-money stock options. All stock options outstanding during 2012 and 2011 were included in the computation of diluted earnings per share. For 2010, the calculation of diluted earnings per share excluded an immaterial number of out-of-the money stock options that had an anti-dilutive effect. Anti-dilutive shares are excluded from the calculation.

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

Materials, Supplies and Inventories	2012	2011
	(Millions of Dollars)	
Fossil Fuel	$165.5	$169.2
Materials and Supplies	121.9	114.1
Natural Gas in Storage	73.3	98.7
Total	$360.7	$382.0

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

Regulatory Accounting: 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 regulatory assets on the balance sheet and expensed in the periods when they are reflected in rates. We defer regulatory assets pursuant to specific or generic orders issued by our regulators. Additionally, regulators can impose regulatory liabilities upon a regulated company for amounts previously collected from customers and for amounts that are expected to be refunded to customers. In general, regulatory assets are recovered in a period between one to eight years. Regulatory assets associated with pension and OPEB expenses are amortized as a component of pension and OPEB expense. Regulatory assets and liabilities that are expected to be amortized within one year are recorded as current on the balance sheet. For further information, see Note C.

Asset Retirement Obligations: We record a liability 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 regulatory accounting guidance 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. For further information, see Note E.

Derivative Financial Instruments: We have derivative physical and financial instruments which we report at fair value. For further information, see Note K.

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

Restricted Cash: As of December 31, 2012 and 2011, restricted cash consists of the settlement we received from the DOE during the first quarter of 2011, which is being returned, net of costs incurred, to customers. As of December 31, 2012, all restricted cash is classified as current.

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

Goodwill: Goodwill reflects the cost of an acquisition in excess of the fair values assigned to identifiable net assets acquired. As of December 31, 2012 and 2011, we had $441.9 million of goodwill recorded at the utility energy segment, which related to our acquisition of Wisconsin Gas in 2000.

Goodwill is not subject to amortization. However, it is subject to fair value-based rules for measuring impairment, and resulting write-downs, if any, are to be reflected in operating expense. Fair value is assessed 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 as of August 31. There was no impairment to the recorded goodwill balance as of our annual 2012 impairment test date.

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 cost to sell. As of December 31, 2012, we had no assets classified as Held for Sale. 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.

Investments: We account for investments in other affiliated companies in which we do not maintain control using the equity method of accounting. We had a total ownership interest of approximately 26.2% in ATC as of December 31, 2012 and 2011. 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 O.

Income Taxes: We follow the liability method in accounting for income taxes. Accounting guidance for income taxes 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. If we conclude that certain deferred tax assets are likely to expire before being realized, a valuation allowance would be established against those 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.

Investment 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 G.

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: We estimate the fair value of stock options using the binomial pricing model. We report unearned stock-based compensation associated with non-vested restricted stock and performance share awards activity within Other Paid in Capital in our Consolidated Statements of Common Equity. We report excess tax benefits as a financing cash inflow. 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 10 years from grant date. For a discussion of the impacts to our Consolidated Financial Statements, see Note H.

The fair value of our stock options was calculated using a binomial option-pricing model using the following weighted-average assumptions:

	2012	2011	2010
Risk-free interest rate	0.1% - 2.0%	0.2% - 3.4%	0.2% - 3.9%
Dividend yield	3.9%	3.9%	3.7%
Expected volatility	19.0%	19.0%	20.3%
Expected life (years)	5.9	5.5	5.9
Expected forfeiture rate	2.0%	2.0%	2.0%
Weighted-average fair value of our stock options granted	$3.34	$3.17	$3.36

B -- RECENT ACCOUNTING PRONOUNCEMENTS

Offsetting Assets and Liabilities: In December 2011, The Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2011-11, Disclosures about Offsetting Assets and Liabilities. The guidance requires enhanced disclosures about derivatives. Both gross and net information related to eligible transactions will be required under the guidance. This guidance is effective for fiscal years and interim periods beginning on or after January 1, 2013 and must be applied retrospectively. Adoption of this guidance may result in additional disclosures related to derivatives beginning in the first quarter of 2013.

C -- REGULATORY ASSETS AND LIABILITIES

Our primary regulator, the PSCW, 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 orders or correspondence with our regulators. These deferred costs will be considered in future rate setting proceedings. As of December 31, 2012 and 2011, we had approximately $6.6 million and $11.0 million, respectively, of net regulatory assets that were not earning a return.

In December 2012, the PSCW issued a rate order effective January 1, 2013 that, among other things, reaffirmed our accounting for the regulatory assets and liabilities identified below.

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

	2012	2011
	(Millions of Dollars)	
Regulatory Assets		
Deferred unrecognized pension costs	$731.5	$647.8
Deferred income tax related	176.5	121.2
Escrowed electric transmission costs	114.1	118.3
Escrowed conservation	73.5	31.5
Deferred unrecognized OPEB costs	61.6	102.9
Deferred plant related -- capital lease	66.6	73.2
Deferred environmental costs	47.4	48.5
Other, net	109.1	122.3
Total regulatory assets	$1,380.3	$1,265.7
Regulatory Liabilities		
Deferred cost of removal obligations	$725.0	$728.2
Escrowed bad debt costs	81.1	69.0
Other, net	62.2	118.7
Total regulatory liabilities	$868.3	$915.9

Regulatory assets and liabilities that are expected to be amortized within one year are recorded as current on the balance sheet.

D -- ASSET SALES, DIVESTITURES AND DISCONTINUED OPERATIONS

Edison Sault: Effective May 4, 2010, we sold Edison Sault Electric Company (Edison Sault) to Cloverland Electric Cooperative for approximately $63.0 million. We reclassified the operations related to Edison Sault as discontinued operations in the accompanying Consolidated Income Statements. Discontinued Edison Sault operations had no significant impact on our Consolidated Statements of Cash Flows for the year ended December 31, 2010. We retained Edison Sault's ownership interest in ATC.

The following table summarizes the net impacts of the discontinued operations on our earnings for the years ended December 31:

	2012	2011	2010
	(Millions of Dollars)		
Income from Continuing Operations	$546.3	$512.8	$454.4
Income from Discontinued Edison Sault operations, net of tax	—	—	0.7
Income from Discontinued other operations, net of tax (a)	—	13.4	1.4
Net Income	$546.3	$526.2	$456.5

(a) Primarily relates to the favorable resolution of uncertain state and federal tax positions associated with our previously discontinued manufacturing business.

Edgewater Generating Unit 5: On March 1, 2011, we sold our 25% interest in Edgewater Generating Unit 5 to WPL for our net book value, including working capital, of approximately $38 million. This transaction was treated as a sale of an asset.

E -- ASSET RETIREMENT OBLIGATIONS

The following table presents the change in our AROs during 2012 and 2011:

	2012	2011
	(Millions of Dollars)	
Balance as of January 1	$55.5	$52.6
Liabilities Incurred	—	0.6
Liabilities Settled	(14.0)	(2.2)
Accretion	2.8	3.0
Cash Flow Revisions	—	1.5
Balance as of December 31	$44.3	$55.5

F -- VARIABLE INTEREST ENTITIES

The primary beneficiary of a variable interest entity must consolidate the related assets and liabilities. Certain disclosures are required by sponsors, significant interest holders in variable interest entities and potential variable interest entities.

We assess our relationships with potential variable interest entities such as our coal suppliers, natural gas suppliers, coal and gas transporters, and other counterparties in power purchase agreements and joint ventures. In making this assessment, we consider the potential that our contracts or other arrangements provide subordinated financial support, the potential for us to absorb losses or rights to residual returns of the entity, the ability to directly or indirectly make decisions about the entities' activities and other factors.

We have identified a purchased power agreement which represents a variable interest. This agreement is for 236 MW of firm capacity from a gas-fired cogeneration facility and we account for it as a capital lease. The agreement includes no minimum energy requirements over the remaining term of approximately 10 years. We have examined the risks of the entity including operations and maintenance, dispatch, financing, fuel costs and other factors, and have determined that we are not the primary beneficiary of the entity. We do not hold an equity or debt interest in the entity and there is no residual guarantee associated with the purchased power agreement.

We have approximately $256.3 million of required payments over the remaining term of this agreement. We believe that the required lease payments under this contract will continue to be recoverable in rates. Total capacity and lease payments under contracts considered variable interests in 2012, 2011 and 2010 were $45.8 million, $65.9 million and $64.2 million, respectively. Our maximum exposure to loss is limited to the capacity payments under the contract.

G -- INCOME TAXES

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

Income Taxes	2012	2011	2010
	(Millions of Dollars)		
Current tax expense (benefit)	$(45.9)	$(166.7)	$144.9
Deferred income taxes, net	353.4	434.8	108.6

Investment tax credit, net	(1.2)	(4.2)	(3.6)
Total Income Tax Expense	$306.3	$263.9	$249.9

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:

Income Tax Expense	2012 Amount	2012 Effective Tax Rate	2011 Amount	2011 Effective Tax Rate	2010 Amount	2010 Effective Tax Rate
	(Millions of Dollars)					
Expected tax at statutory federal tax rates	$298.4	35.0 %	$271.8	35.0 %	$246.5	35.0 %
State income taxes net of federal tax benefit	43.3	5.1 %	40.1	5.2 %	35.8	5.1 %
Production tax credits	(15.9)	(1.9)%	(8.7)	(1.1)%	(7.2)	(1.0)%
Domestic production activities deduction	(12.6)	(1.5)%	(12.6)	(1.6)%	(12.6)	(1.8)%
AFUDC - Equity	(12.3)	(1.4)%	(20.8)	(2.7)%	(11.4)	(1.6)%
Investment tax credit restored	(1.2)	(0.1)%	(4.2)	(0.5)%	(3.6)	(0.5)%
Other, net	6.6	0.7 %	(1.7)	(0.3)%	2.4	0.3 %
Total Income Tax Expense	$306.3	35.9 %	$263.9	34.0 %	$249.9	35.5 %

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

Deferred Tax Assets	2012	2011
	(Millions of Dollars)	
Current		
Employee benefits and compensation	$14.9	$14.6
Other	81.1	57.1
Total Current Deferred Tax Assets	96.0	71.7
Non-current		
Future federal tax benefits	334.7	328.5
Deferred revenues	250.0	279.7
Employee benefits and compensation	97.0	103.6
Property-related	28.3	28.3
Construction advances	22.2	25.4
Other	16.3	35.0
Total Non-Current Deferred Tax Assets	748.5	800.5
Total Deferred Tax Assets	$844.5	$872.2

Deferred Tax Liabilities	2012	2011
	(Millions of Dollars)	
Current		
Prepaid items	$49.7	$50.1
Total Current Deferred Tax Liabilities	49.7	50.1
Non-current		
Property-related	2,339.4	2,020.7
Employee benefits and compensation	244.3	232.8
Investment in transmission affiliate	144.9	129.2
Deferred transmission costs	45.7	47.4
Other	91.2	66.5
Total Non-current Deferred Tax Liabilities	2,865.5	2,496.6
Total Deferred Tax Liabilities	$2,915.2	$2,546.7

Consolidated Balance Sheet Presentation	2012	2011
Current Deferred Tax Asset	$46.3	$21.6
Non-Current Deferred Tax Liability	$2,117.0	$1,696.1

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

As of December 31, 2012, we had approximately $838.5 million and $41.2 million of net operating loss and tax credit carryforwards resulting in deferred tax assets of $293.5 million and $41.2 million, respectively. As of December 31, 2011, we had approximately $867.1 million and $25.0 million of net operating loss and tax credit carryforwards resulting in deferred tax assets of $303.5 million and $25.0 million, respectively. The tax credit and net operating loss carryforwards begin to expire in 2029. We anticipate that we will have future taxable income sufficient to utilize these deferred tax assets.

We adopted accounting guidance related to uncertainty in income taxes. A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

	2012	2011
	(Millions of Dollars)	
Balance as of January 1	$11.1	$29.5
Additions for tax positions of prior years	10.8	—
Reductions for tax positions of prior years	(10.6)	(13.9)
Reductions due to statute of limitations	—	(2.5)
Settlements during the period	—	(2.0)
Balance as of December 31	$11.3	$11.1

The amount of unrecognized tax benefits as of December 31, 2012 and 2011 excludes deferred tax assets related to uncertainty in income taxes of $10.2 million and $11.0 million, respectively. As of December 31, 2012 and 2011, the net amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate for continuing operations was approximately $1.0 million and $0.1 million, respectively.

We recognize interest and penalties accrued related to unrecognized tax benefits as a component of income tax expense. For the years ended December 31, 2012, 2011 and 2010, we recognized approximately $0.2 million,

$0.7 million and $4.1 million, respectively, of accrued interest in the Consolidated Income Statements. For the years ended December 31, 2012 and 2010, we recognized no penalties in the Consolidated Income Statements. For the year ended December 31, 2011, we recognized a benefit of $0.3 million in the Consolidated Income Statements related to a reduction of accrued penalties. We had approximately $0.3 million and $2.0 million of interest accrued and no penalties accrued on the Consolidated Balance Sheets as of December 31, 2012 and 2011, respectively.

Within the next twelve months, it is reasonably possible that our unrecognized tax benefits may decrease by $1.4 million as a result of further IRS guidance relating to an uncertain tax position.

Our primary tax jurisdictions include Federal and the state of Wisconsin. Currently, the tax years of 2007 through 2012 are subject to Federal and Wisconsin examination.

H -- COMMON EQUITY

As of December 31, 2012 and 2011, we had 325,000,000 shares of common stock authorized under our charter, of which 229,039,456 and 230,486,804 common shares, respectively, were outstanding. All share-based compensation is currently fulfilled by purchases on the open market by our independent agents and do not dilute shareholders' ownership.

Share-Based Compensation Plans: We have a plan that was approved by stockholders that enables us to provide a long-term incentive through equity interests in Wisconsin Energy to outside directors, selected officers and key employees of the Company. The plan provides for the granting of stock options, stock appreciation rights, restricted stock awards and performance shares. Awards may be paid in common stock, cash or a combination thereof. We utilize the straight-line attribution method for recognizing share-based compensation expense. Accordingly, for employee awards, equity classified share-based compensation cost is measured at the grant date based on the fair value of the award, and is recognized as expense over the requisite service period. There were no modifications to the terms of outstanding stock options during the period other than necessary adjustments as a result of our stock split.

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

	2012	2011	2010
	(Millions of Dollars)		
Performance units	$16.3	$24.1	$26.0
Stock options	2.7	2.6	7.6
Restricted stock	3.0	1.8	1.5
Share-based compensation expense	$22.0	$28.5	$35.1
Related Tax Benefit	$8.8	$11.4	$14.1

Stock Options: The exercise price of a stock option under the plan is to be no less than 100% of the common stock's fair market value on the grant date and options may not be exercised within six months of the grant date except in the event of a change in control. Option grants consist of non-qualified stock options and vest on a cliff-basis after a three year period. Options expire no later than 10 years from the date of grant. For further information regarding stock-based compensation and the valuation of our stock options, see Note A.

We expect that substantially all of the outstanding options as of December 31, 2012 will be exercised.

The following is a summary of our stock option activity during 2012:

Stock Options	Number of Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (Millions)
Outstanding as of January 1, 2012	10,638,750	$ 21.65		
Granted	938,770	$ 34.88		
Exercised	(2,643,931)	$ 18.84		
Forfeited	(13,920)	$ 28.88		
Outstanding as of December 31, 2012	8,919,669	$ 23.86	5.3	$115.8
Exercisable as of December 31, 2012	7,217,394	$ 22.19	4.6	$105.8

In January 2013, the Compensation Committee of the Board of Directors (Compensation Committee) awarded 1,418,560 non-qualified stock options with an exercise price of $37.46 to our officers and other key employees under its normal schedule of awarding long-term incentive compensation.

The intrinsic value of options exercised during the years ended December 31, 2012, 2011 and 2010 was $47.5 million, $36.1 million and $62.1 million, respectively. Cash received from options exercised during the years ended December 31, 2012, 2011 and 2010 was $49.8 million, $54.4 million and $90.9 million, respectively. The actual tax benefit realized for the tax deductions from option exercises for the same periods was approximately zero, $14.3 million and $24.1 million, respectively.

The following table summarizes information about stock options outstanding as of December 31, 2012:

	Options Outstanding			Options Exercisable		
		Weighted-Average			Weighted-Average	
Range of Exercise Prices	Number of Options	Exercise Price	Remaining Contractual Life (Years)	Number of Options	Exercise Price	Remaining Contractual Life (Years)
$12.71 to $19.74	1,661,507	$18.74	2.5	1,661,507	$18.74	2.5
$21.11 to $24.92	5,877,372	$23.14	5.2	5,429,372	$22.99	5.1
$29.35 to $34.88	1,380,790	$33.09	8.7	126,515	$32.69	8.6
	8,919,669	$23.86	5.3	7,217,394	$22.19	4.6

The following table summarizes information about our non-vested options during 2012:

Non-Vested Stock Options	Number of Options	Weighted- Average Fair Value
Non-Vested as of January 1, 2012	3,103,770	$3.78
Granted	938,770	$3.34
Vested	(2,326,345)	$3.96
Forfeited	(13,920)	$3.29
Non-Vested as of December 31, 2012	1,702,275	$3.31

As of December 31, 2012, total compensation costs related to non-vested stock options not yet recognized was approximately $1.0 million, which is expected to be recognized over the next 21 months on a weighted-average basis.

Restricted Shares: The Compensation Committee has also approved restricted stock grants to certain key employees and directors. The following restricted stock activity occurred during 2012:

Restricted Shares	Number of Shares	Weighted-Average Market Price
Outstanding as of January 1, 2012	192,558	
Granted	94,959	$34.46
Released	(93,250)	$29.87
Forfeited	(6,045)	$31.00
Outstanding as of December 31, 2012	188,222	

Recipients of previously issued restricted shares have the right to vote the shares and receive dividends, and the shares have vesting periods ranging up to 10 years.

In January 2013, the Compensation Committee awarded 74,290 restricted shares to our directors, officers and other key employees under its normal schedule of awarding long-term incentive compensation. These awards have a three-year vesting period, and generally, one-third of the award vests on each anniversary of the grant date. During the vesting period, restricted share recipients also have voting rights and are entitled to dividends in the same manner as other shareholders.

We record the market value of the restricted stock awards on the date of grant and then we charge their value to expense over the vesting period of the awards. The intrinsic value of restricted stock vesting was $3.5 million, $2.5 million and $2.3 million for the years ended December 31, 2012, 2011, and 2010, respectively. The actual tax benefit realized for the tax deductions from released restricted shares for the same years was zero, $0.8 million and $0.7 million, respectively.

As of December 31, 2012, total compensation cost related to restricted stock not yet recognized was approximately $2.6 million, which is expected to be recognized over the next 21 months on a weighted-average basis.

Performance Units: In January 2012, 2011 and 2010, the Compensation Committee awarded 346,570, 435,690 and 555,830 performance units, respectively, to officers and other key employees under the Wisconsin Energy Performance Unit Plan. Under the grants, the ultimate number of units that will be awarded is dependent upon the achievement of certain financial performance of our stock over a three-year period. Under the terms of the award, participants may earn between 0% and 175% of the base performance unit award. All grants are settled in cash. We are accruing compensation costs over the three-year performance period based on our estimate of the final expected value of the awards. Performance units earned as of December 31, 2012, 2011 and 2010 vested and were settled during the first quarter of 2013, 2012 and 2011 and had a total intrinsic value of $19.3 million, $26.7 million and $12.6 million, respectively. The actual tax benefit realized for the tax deductions from the distribution of performance units was approximately $7.0 million, $9.7 million and $4.3 million, respectively.

In January 2013, the Compensation Committee awarded 239,120 performance units to our officers and other key employees under its normal schedule of awarding long-term incentive compensation.

As of December 31, 2012, total compensation cost related to performance units not yet recognized was approximately $13.7 million, which is expected to be recognized over the next 19 months on a weighted-average basis.

Restrictions: Wisconsin Energy's ability as a holding company to pay common dividends primarily depends on the availability of funds received from its non-utility subsidiary, We Power, and its utility subsidiaries.

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

Wisconsin Electric and Wisconsin Gas are required to maintain capital structures that differ from GAAP as they reflect regulatory adjustments. Consistent with the 2010 rate case order, the 2013 PSCW rate case order requires Wisconsin Electric to maintain a common equity ratio range of between 48.5% and 53.5%, and Wisconsin Gas to maintain a capital structure which has a common equity range of between 45.0% and 50.0%. Each company is in compliance with its respective common equity range. Wisconsin Electric and Wisconsin Gas must obtain PSCW approval if they pay dividends above the test year levels that would cause either company to fall below the authorized levels of common equity.

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

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

As of December 31, 2012, the restricted net assets of consolidated and unconsolidated subsidiaries and our equity in undistributed earnings of 50% or less owned investees accounted for by the equity method total approximately $3.6 billion. This amount exceeds 25% of our consolidated net assets as of December 31, 2012.

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

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

Share Repurchase Program: We do not expect to issue new shares under our various employee benefit plans and our dividend reinvestment and share purchase plan; rather, we instruct independent plan agents to purchase the shares in the open market. In that regard, no new shares of common stock were issued in 2012, 2011 or 2010.

In May 2011, our Board of Directors authorized a share repurchase program for up to $300 million of our common stock through the end of 2013. The repurchase program does not obligate Wisconsin Energy to acquire any specific number of shares and may be suspended or terminated by the Board of Directors at any time. Through December 31, 2012, we repurchased approximately 4.7 million shares pursuant to this program at an average cost of $32.63 per share and a total cost of $151.8 million. In addition, through our independent agents, we purchase shares on the open market to fulfill exercised stock options and restricted stock awards. The following table identifies the shares purchased by the Company for the year ending December 31:

	2012		2011		2010	
	Shares	Cost	Shares	Cost	Shares	Cost
	(In Millions)					
Under May 2011 share repurchase program	1.5	$51.8	3.2	$100.0	—	$—
To fulfill exercised stock options and restricted stock awards	2.8	101.4	3.0	93.9	5.8	156.6
Total	4.3	$153.2	6.2	$193.9	5.8	$156.6

I -- LONG-TERM DEBT AND CAPITAL LEASE OBLIGATIONS

Debentures and Notes: As of December 31, 2012, the maturities and sinking fund requirements of our long-term debt outstanding (excluding obligations under capital leases) were as follows:

	(Millions of Dollars)
2013	$396.3
2014	322.4
2015	399.5
2016	27.4
2017	29.5
Thereafter	3,597.8
Total	$4,772.9

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

In December 2012, Wisconsin Electric issued $250 million of 3.65% Debentures due December 15, 2042. The debentures were issued under an existing shelf registration statement filed with the SEC in February 2011. The net proceeds were used to repay short-term debt and for other general corporate purposes.

In September 2011, Wisconsin Electric issued $300 million of 2.95% Debentures due September 15, 2021. The debentures were issued under an existing shelf registration statement filed with the SEC in February 2011. The net proceeds were used to repay short-term debt and for other general corporate purposes.

On April 1, 2011, we used cash and short-term borrowings to retire $450 million of long-term debt that matured.

In January 2011, we issued a total of $420 million in long-term debt ($205 million aggregate principal amount of 4.673% Series B Senior Notes due January 19, 2031 and $215 million aggregate principal amount of 5.848% Series B Senior Notes due January 19, 2041) and used the net proceeds to repay short-term debt incurred to finance the construction of OC 2 and for other corporate purposes. The Series B Senior Notes are secured by a collateral assignment of the leases between ERGSS and Wisconsin Electric related to OC 2.

In February 2010, we issued a total of $530 million in long-term debt ($255 million aggregate principal amount of 5.209% Series A Senior Notes due February 11, 2030 and $275 million aggregate principal amount of 6.09% Series A Senior Notes due February 11, 2040) and used the net proceeds to repay debt incurred to finance the construction of OC 1. The Series A Senior Notes are secured by a collateral assignment of the leases between ERGSS and Wisconsin Electric related to OC 1.

During 2010, we retired $281.5 million of unsecured notes through the issuance of long-term and short-term debt.

Wisconsin Electric is the obligor under two series of tax-exempt pollution control refunding bonds in outstanding principal amount of $147 million. In August 2009, Wisconsin Electric terminated letters of credit that provided credit and liquidity support for the bonds, which resulted in a mandatory tender of the bonds. Wisconsin Electric purchased the bonds at par plus accrued interest to the date of purchase. As of December 31, 2012 and 2011, the repurchased bonds were still outstanding, but were reported as a reduction in our consolidated long-term debt because they are held by Wisconsin Electric. Depending on market conditions and other factors, Wisconsin Electric may change the method used to determine the interest rate on the bonds and have them remarketed to third parties.

In connection with our outstanding Junior Notes, we executed the Replacement Capital Covenant dated May 11, 2007 (RCC) for the benefit of persons that buy, hold or sell a specified series of long-term indebtedness (covered debt). Our 6.20% Senior Notes due April 1, 2033 have been designated as the covered debt under the RCC. The RCC provides that we may not redeem, defease or purchase and our subsidiaries may not purchase any Junior Notes on or before May 15, 2037, unless, subject to certain limitations described in the RCC, during the 180 days prior to the date of redemption, defeasance or purchase, we have received a specified amount of proceeds from the sale of qualifying securities.

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

We treat the long-term power purchase contract as an operating lease for rate-making purposes and we record our minimum lease payments as purchased power expense on the Consolidated Income Statements. We paid a total of $32.5 million and $31.3 million in lease payments during 2012 and 2011, respectively. We record the difference between the minimum lease payments and the sum of imputed interest and amortization costs calculated under capital lease accounting as a deferred regulatory asset on our Consolidated Balance Sheets (see Regulatory Assets - Deferred plant related -- capital lease in Note C). Due to the timing and the amounts of the minimum lease payments, the regulatory asset increased to approximately $78.5 million during 2009, at which time the regulatory asset began to be reduced to zero over the remaining life of the contract. The total obligation under the capital lease was $120.0 million as of December 31, 2012, and will decrease to zero over the remaining life of the contract.

The following is a summary of our capitalized leased facilities as of December 31:

Capital Lease Assets	2012	2011
	(Millions of Dollars)	
Leased Facilities		
Long-term power purchase commitment	$140.3	$140.3
Accumulated amortization	(86.8)	(81.1)
Total Leased Facilities	$53.5	$59.2

Future minimum lease payments under our capital lease and the present value of our net minimum lease payments as of December 31, 2012 are as follows:

	(Millions of Dollars)
2013	$40.4
2014	41.9
2015	43.5
2016	45.1
2017	13.9
Thereafter	71.5
Total Minimum Lease Payments	256.3
Less: Estimated Executory Costs	(68.4)
Net Minimum Lease Payments	187.9
Less: Interest	(67.9)
Present Value of Net Minimum Lease Payments	120.0
Less: Due Currently	(15.8)
	$104.2

J -- SHORT-TERM DEBT

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

	2012		2011	
Short-Term Debt	Balance	Interest Rate	Balance	Interest Rate
	(Millions of Dollars, except for percentages)			
Commercial paper	$394.6	0.30 %	$669.9	0.27 %

The following information relates to commercial paper for the years ended December 31:

	2012	2011
	(Millions of Dollars, except for percentages)	
Maximum Short-Term Debt Outstanding	$669.9	$717.3
Average Short-Term Debt Outstanding	$481.6	$505.1
Weighted-Average Interest Rate	0.28 %	0.25 %

In December 2012, Wisconsin Energy, Wisconsin Electric and Wisconsin Gas entered into new bank back-up credit facilities to maintain short-term credit liquidity which, among other terms, require the companies to maintain, subject to certain exclusions, a minimum total funded debt to capitalization ratio of less than 70%, 65% and 65%, respectively.

As of December 31, 2012, we had approximately $1.2 billion of available undrawn lines under our bank back-up credit facilities and approximately $394.6 million of commercial paper outstanding that was supported by the available lines of credit. Our bank back-up credit facilities expire in December 2017.

The Wisconsin Energy, Wisconsin Electric and Wisconsin Gas bank back-up credit facilities contain customary covenants, including certain limitations on the respective companies' ability to sell assets. The credit facilities also contain customary events of default, including payment defaults, material inaccuracy of representations and warranties, covenant defaults, bankruptcy proceedings, certain judgments, ERISA defaults and change of control. In addition, pursuant to the terms of Wisconsin Energy's credit agreement, Wisconsin Energy must ensure that certain of its subsidiaries comply with several of the covenants contained therein.

As of December 31, 2012, we were in compliance with all financial covenants.

K -- DERIVATIVE INSTRUMENTS

We utilize derivatives as part of our risk management program to manage the volatility and costs of purchased power, generation and natural gas purchases for the benefit of our customers and shareholders. Our approach is non-speculative and designed to mitigate risk and protect against price volatility. Regulated hedging programs require prior approval by the PSCW.

We record derivative instruments on the balance sheet as an asset or liability measured at its fair value, and changes in the derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are met or we receive regulatory treatment for the derivative. For most energy related physical and financial contracts in our regulated operations that qualify as derivatives, the PSCW allows the effects of the fair market value accounting to be offset to regulatory assets and liabilities. We do not offset fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral against fair value amounts recognized for derivatives executed with the same counterparty under the same master netting arrangement. As of December 31, 2012, we recognized $7.6 million in regulatory assets and $17.5 million in regulatory liabilities related to derivatives in comparison to $29.6 million in regulatory assets and $21.7 million in regulatory liabilities as of December 31, 2011.

We record our current derivative assets on the balance sheet in other current assets and the current portion of the liabilities in other current liabilities. The long-term portion of our derivative assets of $0.6 million is recorded in other deferred charges and other assets, and we had no long-term portion of derivative liabilities. Our Consolidated Balance Sheets as of December 31, 2012 and 2011 include:

	December 31, 2012		December 31, 2011	
	Derivative Asset	Derivative Liability	Derivative Asset	Derivative Liability
	(Millions of Dollars)			
Natural Gas	$1.7	$0.5	$2.1	$9.1
Fuel Oil	0.4	—	0.3	0.1
FTRs	4.7	—	5.7	—
Coal	11.1	—	12.5	—
Total	$17.9	$0.5	$20.6	$9.2

Our Consolidated Income Statements include gains (losses) on derivative instruments used in our risk management strategies under fuel and purchased power for those commodities supporting our electric operations and under cost of gas sold for the natural gas sold to our customers. Our estimated notional volumes and gains (losses) for the years ended December 31 were as follows:

	2012		2011	
	Volume	Gains (Losses) (Millions of Dollars)	Volume	Gains (Losses) (Millions of Dollars)
Natural Gas	77.2 million Dth	$(36.3)	71.8 million Dth	$(33.4)
Fuel Oil	7.0 million gallons	1.8	13.0 million gallons	6.9
FTRs	20,616 MW	6.1	23,718 MW	12.5
Total		$(28.4)		$(14.0)

As of December 31, 2012 and 2011, we posted collateral of $2.9 million and $11.9 million, respectively, in our margin accounts. These amounts are recorded on the balance sheets in other current assets.

L -- FAIR VALUE MEASUREMENTS

Fair value measurements require enhanced disclosures about assets and liabilities that are measured and reported at fair value and establish a hierarchal disclosure framework which prioritizes and ranks the level of observable inputs used in measuring fair value.

Fair value is the price that would be received upon the sale of an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We primarily apply the market approach for recurring fair value measurements and attempt to utilize the best available information. Accordingly, we also utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. We are able to classify fair value balances based on the observability of those inputs. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3).

Assets and liabilities measured and reported at fair value are classified and disclosed in one of the following categories:

Level 1 -- Pricing inputs are unadjusted quoted prices available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Instruments in this category consist of financial instruments such as exchange-traded derivatives, cash equivalents and restricted cash investments.

Level 2 -- Pricing inputs are other than quoted prices in active markets, which are either directly or indirectly observable as of the reporting date, and fair value is determined through the use of models or other valuation methodologies. Instruments in this category include non-exchange-traded derivatives such as OTC forwards and options.

Level 3 -- Pricing inputs include significant inputs that are generally less observable from objective sources. The inputs in the determination of fair value require significant management judgment or estimation. At each balance sheet date, we perform an analysis of all instruments subject to fair value reporting and include in Level 3 all instruments whose fair value is based on significant unobservable inputs.

In certain cases, the inputs used to measure fair value may fall into different levels of the fair value hierarchy. In such cases, an instrument's level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and considers factors specific to the instrument.

The following tables summarize our financial assets and liabilities by level within the fair value hierarchy:

Recurring Fair Value Measures	As of December 31, 2012			
	Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Assets:				
Restricted Cash	$2.7	$—	$—	$2.7
Derivatives	0.9	12.3	4.7	17.9
Total	$3.6	$12.3	$4.7	$20.6
Liabilities:				
Derivatives	$0.5	$—	$—	$0.5
Total	$0.5	$—	$—	$0.5

Recurring Fair Value Measures	As of December 31, 2011			
	Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Assets:				
Restricted Cash	$45.5	$—	$—	$45.5
Derivatives	0.3	14.6	5.7	20.6
Total	$45.8	$14.6	$5.7	$66.1
Liabilities:				
Derivatives	$8.2	$1.0	$—	$9.2
Total	$8.2	$1.0	$—	$9.2

Restricted cash consists of certificates of deposit and government backed interest bearing securities and represents the settlement we received from the DOE during the first quarter of 2011, which is being returned, net of costs incurred, to customers. Derivatives reflect positions we hold in exchange-traded derivative contracts and OTC derivative contracts. Exchange-traded derivative contracts, which include futures and exchange-traded options, are generally based on unadjusted quoted prices in active markets and are classified within Level 1. Some OTC derivative contracts are valued using broker or dealer quotations, or market transactions in either the listed or OTC markets utilizing a mid-market pricing convention (the mid-point between bid and ask prices), as appropriate. In such cases, these derivatives are classified within Level 2. Certain OTC derivatives may utilize models to measure fair value. Generally, we use a similar model to value similar instruments. Valuation models utilize various inputs which include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, other observable inputs for the asset or liability, and market-corroborated inputs (i.e., inputs derived principally from or corroborated by observable market data by correlation or other means). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. Certain OTC derivatives are in less active markets with a lower availability of pricing information which might not be observable in or corroborated by the market. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized in Level 3.

The following table summarizes the changes to derivatives classified as Level 3 in the fair value hierarchy:

	2012	2011
	(Millions of Dollars)	
Balance as of January 1	$5.7	$5.9
Realized and unrealized gains (losses)	—	—
Purchases	11.0	16.1
Issuances	—	—
Settlements	(12.0)	(16.3)
Transfers in and/or out of Level 3	—	—
Balance as of December 31	$4.7	$5.7
Change in unrealized gains (losses) relating to instruments still held as of December 31	$—	$—

Derivative instruments reflected in Level 3 of the hierarchy include MISO FTRs that are measured at fair value each reporting period using monthly or annual auction shadow prices from relevant auctions. Changes in fair value for Level 3 recurring items are recorded on our balance sheet. See Note K -- Derivative Instruments, for further information on the offset to regulatory assets and liabilities.

The carrying amount and estimated fair value of certain of our recorded financial instruments as of December 31 are as follows:

Financial Instruments	2012 Carrying Amount	Fair Value	2011 Carrying Amount	Fair Value
	(Millions of Dollars)			
Preferred stock, no redemption required	$30.4	$26.0	$30.4	$25.1
Long-term debt including current portion	$4,772.9	$5,447.3	$4,541.4	$5,179.9

The carrying value of net accounts receivable, accounts payable and short-term borrowings approximates fair value due to the short-term nature of these instruments. The fair value of our preferred stock is estimated based upon the quoted market value for the same or similar issues. The fair value of our long-term debt, including the current portion of long-term debt, but excluding capitalized leases and unamortized discount on debt, is estimated based upon quoted market value for the same or similar issues or upon the quoted market prices of U.S. Treasury issues having a similar term to maturity, adjusted for the issuing company's bond rating and the present value of future cash flows.

M -- BENEFITS

Pensions and Other Post-retirement Benefits: We have defined benefit pension plans that cover substantially all of our employees. Generally, employees who started with the company after 1995 receive a benefit based on a percentage of their annual salary plus an interest credit, while employees who started before 1996 receive a benefit based upon years of service and final average salary. Approximately half of our projected benefit obligation relates to benefits based upon years of service and final average salary.

We also have OPEB plans covering substantially all of our employees. The health care plans are contributory with participants' contributions adjusted annually; the life insurance plans are noncontributory. The accounting for the health care plans anticipates future cost-sharing changes to the written plans that are consistent with our expressed intent to maintain the current cost sharing levels. The post-retirement health care plans include a limit on our share of costs for recent and future retirees.

We use a year-end measurement date to measure the funded status of all of our pension and OPEB plans. Due to the regulated nature of our business, we have concluded that substantially all of the unrecognized costs resulting from the recognition of the funded status of our pension and OPEB plans qualify as a regulatory asset.

The following table presents details about our pension and OPEB plans:

	Pension		OPEB	
	2012	2011	2012	2011
	(Millions of Dollars)			
Change in Benefit Obligation				
Benefit Obligation at January 1	$1,330.6	$1,222.8	$389.7	$368.3
Service cost	21.7	15.9	10.3	10.4
Interest cost	65.5	67.6	20.3	20.8
Participants' contributions	—	—	9.6	11.6
Plan amendments	—	—	0.5	0.4
Actuarial loss (gain)	166.5	98.0	(23.8)	7.6
Other accrued benefits	31.4	—	—	—
Gross benefits paid	(107.2)	(73.7)	(26.3)	(30.3)
Federal subsidy on benefits paid	N/A	N/A	0.9	0.9
Benefit Obligation at December 31	$1,508.5	$1,330.6	$381.2	$389.7
Change in Plan Assets				
Fair Value at January 1	$1,262.5	$1,059.5	$255.4	$216.7
Actual earnings on plan assets	127.4	33.8	29.0	9.0
Employer contributions	102.7	242.9	17.7	48.4
Participants' contributions	—	—	9.6	11.6
Gross benefits paid	(107.2)	(73.7)	(26.3)	(30.3)
Fair Value at December 31	$1,385.4	$1,262.5	$285.4	$255.4
Net Liability	$123.1	$68.1	$95.8	$134.3

As of December 31, 2012, our qualified and non-qualified pension plans were under-funded by $20.9 million and $102.2 million, respectively. As of December 31, 2011, our qualified pension plans were over-funded by $24.4 million and our non-qualified pension plans were underfunded by $92.5 million.

Amounts recognized in our Consolidated Balance Sheets as of December 31 related to the funded status of the benefit plans consisted of:

	Pension		OPEB	
	2012	2011	2012	2011
	(Millions of Dollars)			
Other deferred charges	$—	$—	$25.1	$20.3
Other long-term liabilities	123.1	68.1	120.9	154.6

Net liability	$123.1	$68.1	$95.8	$134.3

The accumulated benefit obligation for all defined benefit plans was $1,507.1 million and $1,329.4 million as of December 31, 2012 and 2011, respectively.

The following table shows the amounts that have not yet been recognized in our net periodic benefit cost as of December 31 and are recorded as a regulatory asset on our balance sheet:

	Pension		OPEB	
	2012	2011	2012	2011
	(Millions of Dollars)			
Net actuarial loss	$719.2	$633.4	$65.3	$108.1
Prior service costs (credits)	12.2	14.4	(3.7)	(6.1)
Transition obligation	—	—	—	0.3
Total	$731.4	$647.8	$61.6	$102.3

We estimate that 2013 periodic pension and OPEB costs will include the amortization of previously unrecognized benefit costs referred to above of $56.0 million and $1.5 million, respectively.

The components of net periodic pension and OPEB costs for the years ended December 31 are as follows:

	Pension			OPEB		
	2012	2011	2010	2012	2011	2010
	(Millions of Dollars)					
Net Periodic Benefit Cost						
Service cost	$21.7	$15.9	$23.7	$10.3	$10.4	$11.2
Interest cost	65.5	67.6	68.4	20.3	20.8	21.2
Expected return on plan assets	(89.6)	(82.1)	(78.2)	(19.0)	(16.9)	(14.3)
Amortization of:						
Transition obligation	—	—	—	0.3	0.3	0.3
Prior service cost (credit)	2.2	2.2	2.2	(1.9)	(1.9)	(11.9)
Actuarial loss	41.0	34.0	26.8	7.3	6.2	10.8
Other	0.4	—	—	—	—	(0.4)
Net Periodic Benefit Cost	$41.2	$37.6	$42.9	$17.3	$18.9	$16.9

In addition to the costs above, in 2011 we recorded net pension costs of less than $0.04 per share related to the settlement of pension litigation. See Note P -- Commitments and Contingencies in this report. The charges were after considering insurance and reserves established in 2010.

	Pension			OPEB		
	2012	2011	2010	2012	2011	2010
Weighted-Average assumptions used to determine benefit obligations as of Dec. 31						
Discount rate	4.10%	5.05%	5.60%	4.15%	5.20%	5.70%
Rate of compensation increase	4.0%	4.0%	4.0%	N/A	N/A	N/A
Weighted-Average assumptions used to determine net cost for year ended Dec. 31						
Discount rate	5.05%	5.60%	6.05%	5.20%	5.70%	5.75%
Expected return on plan assets	7.25%	7.25%	7.25%	7.50%	7.50%	7.50%
Rate of compensation increase	4.0%	4.0%	4.0%	N/A	N/A	N/A

Assumed health care cost trend rates as of Dec. 31	2012	2011	2010
Health care cost trend rate assumed for next year (Pre 65 / Post 65)	7.5%/7.5%	8.0%/12%	7.5%/16%
Rate that the cost trend rate gradually adjusts to	5.0%	5.0%	5.0%
Year that the rate reaches the rate it is assumed to remain at (Pre 65 / Post 65)	2017/2017	2017/2017	2015/2016

The expected long-term rate of return on pension and OPEB plan assets was 7.25% and 7.50%, respectively, in 2012, 2011 and 2010. We consult with our investment advisors on an annual basis to help us forecast expected long-term returns on plan assets by reviewing historical returns as well as calculating expected total trust returns using the weighted-average of long-term market returns for each of the major target asset categories utilized in the fund.

A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	1% Increase	1% Decrease
	(Millions of Dollars)	
Effect on		
Post-retirement benefit obligation	$27.8	$(23.5)
Total of service and interest cost components	$4.0	$(3.2)

We use various Employees' Benefit Trusts to fund a major portion of OPEB. The majority of the trusts' assets are mutual funds.

Plan Assets: Current pension trust assets and amounts which are expected to be contributed to the trusts in the future are expected to be adequate to meet pension payment obligations to current and future retirees.

The Investment Trust Policy Committee oversees investment matters related to all of our funded benefit plans. The Committee works with external actuaries and investment consultants on an on-going basis to establish and monitor investment strategies and target asset allocations. Forecasted cash flows for plan liabilities are regularly updated based on annual valuation results. Target allocations are determined utilizing projected benefit payment cash flows and risk analyses of appropriate investments. They are intended to reduce risk, provide long-term financial stability for the plans and maintain funded levels which meet long-term plan obligations while preserving sufficient liquidity for near-term benefit payments.

Our current pension plan target asset allocation is 45% equity investments and 55% fixed income investments. The current OPEB target asset allocation is 60% equity investments and 40% fixed income investments. Equity securities include investments in large-cap, mid-cap and small-cap companies primarily located in the United States. Fixed income securities include corporate bonds of companies from diversified industries, mortgage and other asset backed securities, commercial paper, and U.S. Treasuries.

The following table summarizes the fair value of our pension plan assets by asset category within the fair value hierarchy (for further level information, see Note L):

Asset Category - Pension	As of December 31, 2012 Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Cash and Cash Equivalents	$13.7	$—	$—	$13.7
Equities:				
U.S. Equity	466.3	—	—	466.3
International Equity	134.7	30.4	—	165.1
Fixed Income				
Short, Intermediate and Long-term Bonds (a)				
U.S. Bonds	67.7	546.6	—	614.3
International Bonds	80.7	45.3	—	126.0
Total	$763.1	$622.3	$—	$1,385.4

Asset Category - Pension	As of December 31, 2011 Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Cash and Cash Equivalents	$8.5	$—	$—	$8.5
Equities:				
U.S. Equity	455.1	—	—	455.1
International Equity	100.4	33.9	—	134.3
Fixed Income				
Short, Intermediate and Long-term Bonds (a)				
U.S. Bonds	76.9	502.8	—	579.7
International Bonds	40.9	44.0	—	84.9
Total	$681.8	$580.7	$—	$1,262.5

(a) This category represents investment grade bonds of U.S. and foreign issuers denominated in U.S. dollars from diverse industries.

The following table summarizes the fair value of our OPEB plan assets by asset category within the fair value hierarchy:

Asset Category - OPEB	As of December 31, 2012 Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Cash and Cash Equivalents	$1.7	$—	$—	$1.7
Equities:				
U.S. Equity	125.9	—	—	125.9
International Equity	39.9	2.2	—	42.1
Fixed Income:				
Short, Intermediate and Long-term Bonds (a)				
U.S. Bonds	5.0	89.9	—	94.9
International Bonds	15.4	5.4	—	20.8

Total	$187.9	$97.5	$—	$285.4

	As of December 31, 2011			
Asset Category - OPEB	Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Cash and Cash Equivalents	$2.4	$—	$—	$2.4
Equities:				
U.S. Equity	113.6	—	—	113.6
International Equity	32.1	2.3	—	34.4
Fixed Income:				
Short, Intermediate and Long-term Bonds (a)				
U.S. Bonds	8.2	83.0	—	91.2
International Bonds	8.7	5.1	—	13.8
Total	$165.0	$90.4	—	$255.4

(a) This category represents investment grade bonds of U.S. and foreign issuers denominated in U.S. dollars from diverse industries.

Cash Flows:

Employer	Pension		
Contributions	Qualified	Non-Qualified	OPEB
	(Millions of Dollars)		
2010	$—	$6.8	$4.9
2011	$236.4	$6.5	$48.4
2012	$95.6	$7.1	$17.7

The following table identifies our expected benefit payments over the next 10 years:

Year	Pension	Gross OPEB
	(Millions of Dollars)	
2013	$101.4	$23.3
2014	$99.5	$20.8
2015	$98.9	$21.0
2016	$99.1	$21.5
2017	$99.8	$22.2
2018-2022	$489.4	$113.9

Savings Plans: We sponsor savings plans which allow employees to contribute a portion of their pre-tax and/or after-tax income in accordance with plan-specified guidelines. Under these plans, we expensed matching contributions of $13.8 million, $14.1 million and $13.8 million during 2012, 2011 and 2010, respectively.

Postemployment Benefits: Postemployment benefits provided to former or inactive employees are recognized when an event occurs. The estimated liability for such benefits was $4.0 million as of December 31, 2012.

N -- SEGMENT REPORTING

Our reportable segments as of December 31, 2012 include a utility energy segment and a non-utility energy segment. We have organized our reportable segments based upon the regulatory environment in which our utility subsidiaries operate and on how management makes decisions and measures performance. The segments are managed separately because each business requires different technology and marketing strategies. The accounting policies of the reportable operating segments are the same as those described in Note A.

Our utility energy segment primarily includes our electric and natural gas utility operations. Our electric utility operation engages in the generation, distribution and sale of electric energy in southeastern (including metropolitan Milwaukee), east central and northern Wisconsin and in the Upper Peninsula of Michigan. Our natural gas utility operation is engaged in the purchase, distribution and sale of natural gas to retail customers and the transportation of customer-owned natural gas throughout Wisconsin. Our non-utility energy segment derives its revenues primarily from the ownership of electric power generating facilities for long-term lease to Wisconsin Electric.

Summarized financial information concerning our reportable segments for each of the three years ended December 31, 2012 is shown in the following table. The segment information below includes income from discontinued operations as a result of the sale of Edison Sault in May 2010.

	Reportable Segments			Eliminations	
	Energy		Corporate &	& Reconciling	Total
Year Ended	Utility	Non-Utility	Other (a)	Items	Consolidated
	(Millions of Dollars)				
December 31, 2012					
Operating Revenues (b)	$4,190.8	$439.9	$1.2	$(385.5)	$4,246.4
Depreciation and Amortization	$296.4	$67.1	$0.7	$—	$364.2
Operating Income (Loss)	$647.7	$358.8	$(6.2)	$—	$1,000.3
Equity in Earnings of Unconsolidated Affiliates	$65.7	$—	$(0.2)	$—	$65.5
Interest Expense, Net	$129.4	$66.7	$52.5	$(0.4)	$248.2
Income Tax Expense (Benefit)	$214.9	$116.6	$(25.2)	$—	$306.3
Income from Discontinued Operations, Net of Tax	$—	$—	$—	$—	$—
Net Income (Loss)	$400.6	$175.9	$546.1	$(576.3)	$546.3
Capital Expenditures	$697.3	$5.5	$4.2	$—	$707.0
Total Assets (c)	$13,988.1	$2,903.5	$4,431.4	$(7,038.0)	$14,285.0
December 31, 2011					
Operating Revenues (b)	$4,431.5	$435.1	$0.9	$(381.1)	$4,486.4
Depreciation and Amortization	$257.0	$72.5	$0.7	$—	$330.2
Operating Income (Loss)	$544.8	$348.9	$(6.4)	$—	$887.3
Equity in Earnings of Unconsolidated Affiliates	$62.5	$—	$(0.9)	$—	$61.6
Interest Expense, Net	$110.0	$66.7	$59.5	$(0.4)	$235.8
Income Tax Expense (Benefit)	$182.7	$112.8	$(31.6)	$—	$263.9
Income from Discontinued Operations, Net of Tax	$—	$—	$13.4	$—	$13.4
Net Income (Loss)	$376.3	$169.8	$525.9	$(545.8)	$526.2
Capital Expenditures	$792.2	$31.2	$7.4	$—	$830.8
Total Assets (c)	$13,433.5	$2,949.0	$4,694.8	$(7,215.2)	$13,862.1

	Reportable Segments			Eliminations &	
	Energy		Corporate &	Reconciling	Total
Year Ended	Utility	Non-Utility	Other (a)	Items	Consolidated
	(Millions of Dollars)				
December 31, 2010					
Operating Revenues (b)	$4,165.3	$320.2	$0.5	$(283.5)	$4,202.5
Depreciation and Amortization	$251.4	$53.5	$0.7	$—	$305.6
Operating Income (Loss)	$564.0	$252.4	$(6.0)	$—	$810.4
Equity in Earnings of Unconsolidated Affiliates	$60.1	$—	$(0.2)	$—	$59.9
Interest Expense, Net	$117.2	$40.3	$52.8	$(3.9)	$206.4
Income Tax Expense (Benefit)	$192.1	$84.9	$(27.1)	$—	$249.9
Income from Discontinued Operations, Net of Tax	$0.7	$—	$1.4	$—	$2.1
Net Income (Loss)	$354.2	$128.4	$456.4	$(482.5)	$456.5
Capital Expenditures	$687.0	$109.3	$1.9	$—	$798.2
Total Assets (c)	$11,997.4	$2,914.2	$5,075.9	$(6,927.7)	$13,059.8

(a) Corporate & Other includes all other non-utility activities, primarily non-utility real estate investment and development by Wispark as well as interest on corporate debt.

(b) An elimination for intersegment revenues is included in Operating Revenues. This elimination is primarily between We Power and Wisconsin Electric.

(c) An elimination of $2,286.7 million, $2,369.0 million and $1,785.9 million is included in Total Assets as of December 31, 2012, 2011 and 2010, respectively, for all PTF-related activity between We Power and Wisconsin Electric.

O -- RELATED PARTIES

We receive and/or provide certain services to other associated companies in which we have an equity investment.

American Transmission Company LLC: As of December 31, 2012, we have a 26.2% interest in ATC. We pay ATC for transmission and other related services it provides. In addition, we provide a variety of operational, maintenance and project management work for ATC, which are reimbursed to us by ATC. We are required to pay the cost of needed transmission infrastructure upgrades for new generation projects while projects are under construction, including the new generating units constructed as part of our PTF strategy. ATC reimburses us for these costs when new generation is placed in service. As of December 31, 2012 and 2011, we had a receivable of zero and $5.4 million, respectively, for these items. During the years ended December 31, 2012, 2011 and 2010, our equity in earnings from ATC was $65.7 million, $62.5 million and $60.1 million, respectively. During the years ended December 31, 2012, 2011 and 2010, distributions received from ATC were $52.6 million, $49.7 million and $49.3 million, respectively.

We provided and received services from the following associated companies during 2012, 2011 and 2010:

Equity Investee	2012	2011	2010
	(Millions of Dollars)		
Services Provided			

–ATC	$8.2	$10.8	$16.9
Services Received			
–ATC	$222.7	$219.2	$220.8

As of December 31, 2012 and 2011, our Consolidated Balance Sheets included receivable and payable balances with ATC as follows:

Equity Investee	2012	2011
	(Millions of Dollars)	
Services Provided –ATC	$0.5	$0.7
Services Received –ATC	$18.6	$18.1

P -- COMMITMENTS AND CONTINGENCIES

Capital Expenditures: We have made certain commitments in connection with 2013 capital expenditures. During 2013, we estimate that total capital expenditures will be approximately $692.7 million.

Operating Leases: We enter into long-term purchase power contracts to meet a portion of our anticipated increase in future electric energy supply needs. These contracts expire at various times through 2018. Certain of these contracts were deemed to qualify as operating leases. In addition, we have various other operating leases including leases for coal cars.

Future minimum payments for the next five years and thereafter for our operating lease contracts are as follows:

	(Millions of Dollars)
2013	$6.5
2014	3.9
2015	3.9
2016	3.7
2017	3.2
Thereafter	25.9
Total	$47.1

Divested Assets: Pursuant to the sale of Point Beach, we have agreed to indemnification provisions customary to transactions involving the sale of nuclear assets. We also provided customary indemnifications to WPL in connection with the sale of our interest in Edgewater Generating Unit 5.

Environmental Matters: We periodically review our exposure for environmental remediation costs as evidence becomes available indicating that our liability has changed. Given current information, including the following, we believe that future costs in excess of the amounts accrued and/or disclosed on all presently known and quantifiable environmental contingencies will not be material to our financial position or results of operations.

We have a program of comprehensive environmental remediation planning for former manufactured gas plant sites and coal combustion product disposal sites. We perform ongoing assessments of manufactured gas plant sites and related disposal sites used by Wisconsin Electric and Wisconsin Gas, and coal combustion product disposal/landfill sites used by Wisconsin Electric, as discussed below. We are working with the WDNR in our investigation and remediation planning. At this time, we cannot estimate future remediation costs associated with these sites beyond those described below.

Manufactured Gas Plant Sites: We have identified several sites at which Wisconsin Electric, Wisconsin Gas, or a predecessor company historically owned or operated a manufactured gas plant. These sites have been substantially remediated or are at various stages of investigation, monitoring and remediation. We have also identified other sites that may have been impacted by historical manufactured gas plant activities. Based upon on-going analysis, we estimate that the future costs for detailed site investigation and future remediation costs may range from $16 million to $62 million over the next ten years. This estimate is dependent upon several variables including, among other things, the extent of remediation, changes in technology and changes in regulation. As of

December 31, 2012 and 2011, we established reserves of $38.2 million and $37.5 million, respectively, related to future remediation costs.

Historically, the PSCW has allowed Wisconsin utilities, including Wisconsin Electric and Wisconsin Gas, to defer the costs spent on the remediation of manufactured gas plant sites, and has allowed for these costs to be recovered in rates over five years. Accordingly, we have recorded a regulatory asset for remediation costs.

Coal Combustion Product Landfill Sites: Wisconsin Electric aggressively seeks environmentally acceptable, beneficial uses for its coal combustion products. However, some coal combustion products have been, and to a small degree continue to be, managed in company-owned, licensed landfills. Some early designed and constructed landfills have at times required various levels of monitoring or remediation. Where Wisconsin Electric has become aware of these conditions, efforts have been made to define the nature and extent of any release, and work has been performed to address these conditions. During 2012, 2011 and 2010, Wisconsin Electric incurred $0.3 million, $0.2 million and $0.4 million respectively, in landfill remediation expenses. As of December 31, 2012, we have no reserves established related to coal combustion product landfill sites.

EPA - Consent Decree: In April 2003, Wisconsin Electric reached a Consent Decree with the EPA, in which it agreed to significantly reduce air emissions from its coal-fired generating facilities. In July 2003, the Consent Decree was amended to include the state of Michigan, and in October 2007, the U.S. District Court for the Eastern District of Wisconsin approved and entered the amended Consent Decree. The Consent Decree was further amended in January 2012 to change the point of air monitoring at the Oak Creek Power Plant to accommodate the AQCS that began service in 2012. In order to achieve the reductions agreed to in the Consent Decree, over the past almost 10 years we have installed new pollution control equipment, including the Oak Creek AQCS, upgraded existing equipment and retired certain older coal units at a cost of approximately $1.2 billion. We estimate we will spend an additional $22 million in 2013 for final implementation costs.

Valley Power Plant Title V Air Permit: The WDNR renewed VAPP's Title V operating permit in February 2011. The term of the permit is five years. Sierra Club and Clean Wisconsin requested and were granted an administrative hearing before the WDNR on certain conditions of the permit; however, the case has been stayed. In addition, in March 2011, the Sierra Club petitioned the EPA for additional reductions and monitoring for particulate matter, and revisions to certain applicable requirements. No timeline has been set by the EPA to respond to that petition. In May 2012, the Sierra Club filed a notice of intent to bring suit to force the EPA to issue a response to that petition. We believe that the permit was properly issued and that the plant is in compliance with all applicable regulations and standards. However, if as a result of either proceeding the permit is remanded to the WDNR, the plant will continue to operate under the previous operating permit.

In August 2012, we announced plans to convert the fuel source for VAPP from coal to natural gas and anticipate that the conversion will be completed by the end of 2015 or early 2016. We currently expect the cost of this conversion to be between $60 million and $65 million subject to PSCW approval, and receiving a construction permit from the WDNR. We expect to file for a Certificate of Authority from the PSCW and an air permit from the WDNR during the second quarter of 2013.

We have made significant progress on the four voluntary goals that we submitted in a December 2011 letter to the EPA: (1) we achieved the reductions in annual SO_2 emissions from the plant to no more than 4,500 tons (a 65% decrease from 2001 emission levels); (2) the planned conversion of the plant from coal to natural gas eliminates the requirement to meet the MATS rules and, therefore, the need for a dry sorbent injection system; (3) we held open houses and tours of VAPP to help inform the community on the plant, the unique role that it plays in the community, and to share environmental successes and future plans; and (4) we announced plans for converting VAPP to natural gas fuel by 2015-2016, provided that we can obtain authorization from the PSCW to do so.

Cash Balance Pension Plan: In June 2009, a lawsuit was filed by Alan M. Downes, a former employee, against the Plan in the U.S. District Court for the Eastern District of Wisconsin. The complaint alleged that Plan participants who received a lump sum distribution under the Plan prior to their normal retirement age did not receive the full benefit to which they were entitled in violation of ERISA and were owed additional benefits, because the Plan failed to apply the correct interest crediting rate to project the cash balance account to their normal retirement age. In September 2010, the plaintiff filed a First Amended Class Action Complaint alleging additional claims under ERISA and adding Wisconsin Energy as a defendant.

In November 2011, we entered into a settlement agreement with the plaintiffs for $45.0 million, and the court promptly issued an order preliminarily approving the settlement. As part of the settlement agreement, we agreed to class certification for all similarly situated plaintiffs. The resolution of this matter resulted in a cost of less than $0.04 per share for 2011 after considering insurance and reserves established in 2010. The court approved the settlement and issued its written order in April 2012. Substantially all payments to class members have been made pursuant to the settlement. We do not anticipate further charges as a result of the settlement.

Q -- SUPPLEMENTAL CASH FLOW INFORMATION

During the year ended December 31, 2012, we paid $241.2 million in interest, net of amounts capitalized, and received $107.0 million in net refunds from income taxes. During the year ended December 31, 2011, we paid $234.0 million in interest, net of amounts capitalized, and received $109.1 million in net refunds from income taxes. During the year ended December 31, 2010, we paid $198.0 million in interest, net of amounts capitalized, and paid $166.7 million in income taxes, net of refunds.

As of December 31, 2012, 2011 and 2010, the amount of accounts payable related to capital expenditures was $15.7 million, $16.7 million and $18.2 million, respectively.

During the years ended December 31, 2012, 2011 and 2010, total amortization of deferred revenue was $54.9 million, $54.4 million and $34.6 million, respectively.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Wisconsin Energy Corporation:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Wisconsin Energy Corporation and subsidiaries (the "Company") as of December 31, 2012 and 2011, and the related consolidated statements of income, common equity, and cash flows for each of the three years in the period ended December 31, 2012. Our audits also included the financial statement schedules listed in the Index at Item 15. These financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedules based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Wisconsin Energy Corporation and subsidiaries as of December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2012, based on the criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2013 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/DELOITTE & TOUCHE LLP

Milwaukee, Wisconsin
February 27, 2013

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Wisconsin Energy Corporation:

We have audited the internal control over financial reporting of Wisconsin Energy Corporation and subsidiaries (the "Company") as of December 31, 2012, based on the criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on the criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedules as of and for the year ended December 31, 2012 of the Company and our report dated February 27, 2013 expressed an unqualified opinion on those financial statements and financial statement schedules.

/s/DELOITTE & TOUCHE LLP

Milwaukee, Wisconsin
February 27, 2013

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

Our management, with the participation of our principal executive officer and principal financial officer, has evaluated the effectiveness of our disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this report. Based upon such evaluation, our principal executive officer and principal financial officer have concluded that, as of the end of such period, our disclosure controls and procedures are effective (i) in recording, processing, summarizing and reporting, on a timely basis, information required to be disclosed by us in the reports that we file or submit under the Exchange Act and (ii) to ensure that information required to be disclosed in the reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of Wisconsin Energy Corporation's and subsidiaries' internal control over financial reporting based on the framework in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its evaluation, our management concluded that Wisconsin Energy Corporation's and subsidiaries' internal control over financial reporting was effective as of December 31, 2012.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of the effectiveness of internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Deloitte & Touche LLP, an independent registered public accounting firm, as auditors of our financial statements has issued an attestation report on the effectiveness of Wisconsin Energy Corporation's and its subsidiaries' internal control over financial reporting as of December 31, 2012. Deloitte & Touche LLP's report is included in this report.

Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting during the fourth quarter of 2012 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE OF THE REGISTRANT

The information under "Proposal 1: Election of Directors - Terms Expiring in 2014", "Section 16(a) Beneficial Ownership Reporting Compliance", "Corporate Governance - Frequently Asked Questions: What is the process used to identify director nominees and how do I recommend a nominee to the Corporate Governance Committee?", "Corporate Governance - Frequently Asked Questions: Are the Audit and Oversight, Corporate Governance and Compensation Committees comprised solely of independent directors?", "Corporate Governance - Frequently Asked Questions: Are all the members of the Audit Committee financially literate and does the committee have an 'audit committee financial expert'?" and "Committees of the Board of Directors - Audit and Oversight" in our Definitive Proxy Statement on Schedule 14A to be filed with the SEC for our Annual Meeting of Stockholders to be held May 2, 2013 (the "2013 Annual Meeting Proxy Statement") is incorporated herein by reference. Also see "Executive Officers of the Registrant" in Part I of this report.

We have adopted a written code of ethics, referred to as our Code of Business Conduct, that all of our directors, executive officers and employees, including the principal executive officer, principal financial officer and principal accounting officer, must comply with. We have posted our Code of Business Conduct on our website, www.wisconsinenergy.com. We have not provided any waiver to the Code for any director, executive officer or other employee. Any amendments to, or waivers for directors and executive officers from, the Code of Business Conduct will be disclosed on our website or in a current report on Form 8-K.

Our website, www.wisconsinenergy.com, also contains our Corporate Governance Guidelines and the charters of our Audit and Oversight, Corporate Governance and Compensation Committees.

Our Code of Business Conduct, Corporate Governance Guidelines and committee charters are also available without charge to any stockholder of record or beneficial owner of our common stock by writing to the corporate secretary, Susan H. Martin, at our principal business office, 231 West Michigan Street, P.O. Box 1331, Milwaukee, Wisconsin 53201.

ITEM 11. EXECUTIVE COMPENSATION

The information under "Compensation Discussion and Analysis", "Executive Compensation", "Director Compensation", "Committees of the Board of Directors - Compensation", "Compensation Committee Report", "Risk Analysis of Compensation Policies and Practices" and "Certain Relationships and Related Transactions - Compensation Committee Interlocks and Insider Participation" in the 2013 Annual Meeting Proxy Statement is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The security ownership information called for by Item 12 of Form 10-K is incorporated herein by reference to this information included under "WEC Common Stock Ownership" in the 2013 Annual Meeting Proxy Statement.

EQUITY COMPENSATION PLAN INFORMATION

The following table sets forth information about our equity compensation plans as of December 31, 2012:

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights		(b) Weighted-average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders	8,919,669	(1)	$23.86	33,545,045
Equity compensation plans not approved by security holders	—		—	—
Total	8,919,669		$23.86	33,545,045

(1) Represents options to purchase our common stock granted under our 1993 Omnibus Stock Incentive Plan, amended and restated effective May 5, 2011.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information under "Corporate Governance - Frequently Asked Questions: Who are the independent directors?", "Corporate Governance - Frequently Asked Questions: What are the Board's standards of independence", "Corporate Governance - Frequently Asked Questions: Are the Audit and Oversight, Corporate Governance and Compensation Committees comprised solely of independent directors?", "Corporate Governance - Frequently Asked Questions: Does the Company have policies and procedures in place to review and approve related party transactions?" and "Certain Relationships and Related Transactions" in the 2013 Annual Meeting Proxy Statement is incorporated herein by reference. A full description of the guidelines our Board uses to determine director independence is located in Appendix A of our Corporate Governance Guidelines, which can be found on our website, www.wisconsinenergy.com.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information regarding the fees paid to, and services performed by, our independent auditors and the pre-approval policy of our audit and oversight committee under "Independent Auditors' Fees and Services" in the 2013 Annual Meeting Proxy Statement is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) 1. FINANCIAL STATEMENTS AND REPORTS OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM INCLUDED IN PART II OF THIS REPORT

2. FINANCIAL STATEMENT SCHEDULES INCLUDED IN PART IV OF THIS REPORT

Schedule I, Condensed Parent Company Financial Statements, including Income Statements and Cash Flows for the three years ended December 31, 2012 and Balance Sheets as of December 31, 2012 and 2011.

Schedule II, Valuation and Qualifying Accounts, for the three years ended December 31, 2012.

Other schedules are omitted because of the absence of conditions under which they are required or because the required information is given in the financial statements or notes thereto.

3. EXHIBITS AND EXHIBIT INDEX

See the Exhibit Index included as the last part of this report, which is incorporated herein by reference. Each management contract and compensatory plan or arrangement required to be filed as an exhibit to this report is identified in the Exhibit Index by two asterisks (**) following the description of the exhibit.

WISCONSIN ENERGY CORPORATION

INCOME STATEMENTS
(Parent Company Only)

SCHEDULE I -- CONDENSED PARENT COMPANY
FINANCIAL STATEMENTS

	Year Ended December 31		
	2012	2011	2010
	(Millions of Dollars)		
Other Income, Net	$3.2	$2.7	$4.2
Corporate Expense	4.8	4.8	4.0
Interest Expense	55.7	61.8	53.8
Loss before Taxes	(57.3)	(63.9)	(53.6)
Income Tax Benefit	26.0	30.8	25.9
Loss after Taxes	(31.3)	(33.1)	(27.7)
Equity in Subsidiaries' Continuing Operations	577.6	545.9	482.1
Income from Continuing Operations	546.3	512.8	454.4
Income from Discontinued Operations including Equity in Subsidiaries' Discontinued Operations	—	13.4	2.1
Net Income	$546.3	$526.2	$456.5

See accompanying notes to condensed parent company financial statements.

WISCONSIN ENERGY CORPORATION

STATEMENTS OF CASH FLOWS
(Parent Company Only)

SCHEDULE I - CONDENSED PARENT COMPANY
FINANCIAL STATEMENTS - (Cont'd)

	Year Ended December 31		
	2012	2011	2010
	(Millions of Dollars)		
Operating Activities			
Net income	$546.3	$526.2	$456.5
Reconciliation to cash			
Equity in subsidiaries' earnings	(577.6)	(545.9)	(482.9)
Dividends and distributions from subsidiaries	842.3	995.5	305.3
Deferred income taxes, net	104.4	(350.9)	(29.7)
Accrued income taxes, net	(457.9)	363.4	41.9
Change in - Other current assets	0.2	(0.1)	11.5
Change in - Other current liabilities	(6.7)	8.9	3.0
Change in - Accounts receivable	22.5	(18.7)	477.2
Other, net	(8.1)	(10.2)	(1.4)
Cash Provided by Operating Activities	465.4	968.2	781.4
Investing Activities			
Proceeds from asset sales	—	—	63.1
Capital contributions to associated companies	(21.5)	(36.5)	(64.5)
Capitalized interest and other	12.6	2.4	(57.3)
Cash Used in Investing Activities	(8.9)	(34.1)	(58.7)
Financing Activities			
Exercise of stock options	49.8	54.4	90.9
Purchase of common stock	(153.9)	(193.9)	(156.6)
Dividends paid on common stock	(276.3)	(242.0)	(187.0)
Retirement of long-term debt	—	(450.0)	(281.5)
Change in short-term debt	(79.5)	(116.5)	(310.5)
Change in notes payable due associated companies	3.8	3.9	106.1
Other, net	—	9.9	15.8
Cash Used in Financing Activities	(456.1)	(934.2)	(722.8)
Change in Cash and Cash Equivalents	0.4	(0.1)	(0.1)
Cash and Cash Equivalents at Beginning of Year	0.5	0.6	0.7
Cash and Cash Equivalents at End of Year	$0.9	$0.5	$0.6

See accompanying notes to condensed parent company financial statements.

WISCONSIN ENERGY CORPORATION

BALANCE SHEETS
(Parent Company Only)

SCHEDULE I - CONDENSED PARENT COMPANY
FINANCIAL STATEMENTS - (Cont'd)

	December 31	
	2012	2011
	(Millions of Dollars)	
Assets		
Current Assets		
Cash and cash equivalents	$0.9	$0.5
Accounts and notes receivable from associated companies	32.9	55.8
Prepaid taxes and other	176.3	2.2
Total Current Assets	210.1	58.5
Property and Investments		
Investment in subsidiary companies	4,662.3	4,906.9
Other	2.1	2.6
Total Property and Investments	4,664.4	4,909.5
Deferred Charges and Other Assets	331.4	433.3
Total Assets	$5,205.9	$5,401.3
Liabilities and Equity		
Current Liabilities		
Short-term debt	$67.0	$146.5
Notes payable due associated companies	140.6	136.8
Accrued taxes and other	34.7	327.3
Total Current Liabilities	242.3	610.6
Long-term debt	694.3	693.6
Other Long-term liabilities	134.2	133.8
Stockholder's equity	4,135.1	3,963.3
Total Liabilities and Equity	$5,205.9	$5,401.3

See accompanying notes to condensed parent company financial statements.

WISCONSIN ENERGY CORPORATION

NOTES TO FINANCIAL STATEMENTS
(Parent Company Only)

SCHEDULE I - CONDENSED PARENT COMPANY
FINANCIAL STATEMENTS - (Cont'd)

1. For Parent Company only presentation, investment in subsidiaries are accounted for using the equity method. The condensed Parent Company financial statements and notes should be read in conjunction with the consolidated financial statements and notes of Wisconsin Energy Corporation appearing in this Annual Report on Form 10-K.

2. Wisconsin Energy's ability as a holding company to pay common dividends primarily depends on the availability of funds received from the Parent Company's non-utility subsidiary, We Power, and its principal utility subsidiaries, Wisconsin Electric and Wisconsin Gas. During 2012, Wisconsin Electric and Wisconsin Gas collectively provided Wisconsin Energy with $212.6 million of dividends, and We Power provided $629.7 million of distributions.

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

Wisconsin Energy does not believe that these restrictions will materially affect the Parent Company's operations or limit any dividend payments in the foreseeable future.

3. As of December 31, 2012, the maturities of the Parent Company long-term debt outstanding were as follows:

	(Millions of Dollars)
2013	$—
2014	—
2015	—
2016	—
2017	—
Thereafter	700.0
Total	$700.0

Wisconsin Energy amortizes debt premiums, discounts and debt issuance costs over the lives of the debt and includes the costs in interest expense.

During 2011, Wisconsin Energy used cash and short-term borrowings to retire $450 million of long-term debt that matured.

During 2010, Wisconsin Energy used cash and short-term borrowings to retire $281.5 million of unsecured notes.

Wisconsin Energy entered into a new bank back-up credit facility on December 12, 2012. The facility contains customary covenants, including certain limitations on Wisconsin Energy's ability to sell assets. The credit facility also contains customary events of default, including payment defaults, material inaccuracy of representations and warranties, covenant defaults, bankruptcy proceedings, certain judgments, ERISA defaults and change of control. In addition, pursuant to the terms of the credit facility, Wisconsin Energy must ensure that certain of its subsidiaries comply with several of the covenants contained therein. In addition, Wisconsin Energy is required to maintain, subject to certain exclusions, a minimum total funded debt to capitalization ratio of less than 70%.

As of December 31, 2012, Wisconsin Energy was in compliance with all covenants.

WECC is a subsidiary of Wisconsin Energy and has $80 million of long-term notes outstanding. In a Support

Agreement between WECC and Wisconsin Energy, Wisconsin Energy agreed to make sufficient liquid asset contributions to WECC to permit WECC to service its debt obligations as they become due.

4. Wisconsin Energy and certain of its subsidiaries enter into various guarantees to provide financial and performance assurance to third parties on behalf of affiliates. As of December 31, 2012, Wisconsin Energy had the following guarantees which are eliminated upon consolidation and not included in the Wisconsin Energy Notes to Consolidated Statements:

	Maximum Potential Future Payments	Outstanding as of Dec 31, 2012	Liability Recorded as of Dec 31, 2012
	(Millions of Dollars)		
Wisconsin Energy Guarantees			
Utility	$4.6	$4.6	$—
Non-Utility Energy	55.5	—	—
Other	0.3	—	—
Total	$60.4	$4.6	$—
Letters of Credit	$0.4	$0.4	$—

Utility guarantees support obligations of the utility segment under surety bonds, worker's compensation and agreements.

Wisconsin Energy's guarantees in support of its non-utility energy segment guaranty performance and payment obligations of We Power. The guarantees which support We Power are for obligations under purchase, construction and lease agreements with the utility segment and third parties.

Wisconsin Energy has a guarantee that supports an environmental indemnification obligation, which is unlimited, associated with the Minergy Neenah plant and indemnifications related to the post-closing obligations under the Minergy Neenah sale agreement which was entered into in September 2006. In the event the guarantee fails to perform, Wisconsin Energy would be responsible for the obligations.

5. The carrying amount and estimated fair value of certain of our recorded financial instruments as of December 31 are as follows:

Financial Instruments	2012 Carrying Amount	Fair Value	2011 Carrying Amount	Fair Value
	(Millions of Dollars)			
Long-term debt including current portion	$700.0	$805.9	$700.0	$750.8

The carrying value of net accounts receivable, accounts payable and short-term borrowings approximates fair value due to the short-term nature of these instruments. The fair value of our long-term debt, including the current portion of long-term debt, and unamortized discount on debt, is estimated based upon quoted market value for the same or similar issues or upon the quoted market prices of U.S. Treasury issues having a similar term to maturity, adjusted for the Parent Company's bond rating and the present value of future cash flows.

6. During the year ended December 31, 2012, Wisconsin Energy paid $45.2 million in interest, net of amounts capitalized, and received $128.2 million in refunds from income taxes. During the year ended December 31, 2011, Wisconsin Energy paid $57.7 million in interest, net of amounts capitalized, and received $114.6 million in refunds from income taxes. During the year ended December 31, 2010, Wisconsin Energy paid $43.5 million in interest, net of amounts capitalized, and received $1.0 million in refunds from income taxes.

SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS

Allowance for Doubtful Accounts	Balance at Beginning of the Period	Expense	Deferral	Net Write-offs	Balance at End of the Period
	(Millions of Dollars)				
December 31, 2012	$61.7	$47.7	$(4.0)	$(47.4)	$58.0
December 31, 2011	$58.1	$85.8	$(35.9)	$(46.3)	$61.7
December 31, 2010	$57.9	$86.2	$(32.5)	$(53.5)	$58.1

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

WISCONSIN ENERGY CORPORATION

	By	/s/GALE E. KLAPPA
Date:	February 27, 2013	Gale E. Klappa, Chairman of the Board, President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

/s/GALE E. KLAPPA Gale E. Klappa, Chairman of the Board, President and Chief Executive Officer and Director -- Principal Executive Officer	February 27, 2013
/s/J. PATRICK KEYES J. Patrick Keyes, Executive Vice President and Chief Financial Officer -- Principal Financial Officer	February 27, 2013
/s/STEPHEN P. DICKSON Stephen P. Dickson, Vice President and Controller -- Principal Accounting Officer	February 27, 2013
/s/JOHN F. BERGSTROM John F. Bergstrom, Director	February 27, 2013
/s/BARBARA L. BOWLES Barbara L. Bowles, Director	February 27, 2013
/s/PATRICIA W. CHADWICK Patricia W. Chadwick, Director	February 27, 2013
/s/ROBERT A. CORNOG Robert A. Cornog, Director	February 27, 2013
/s/CURT S. CULVER Curt S. Culver, Director	February 27, 2013
/s/THOMAS J. FISCHER Thomas J. Fischer, Director	February 27, 2013
/s/HENRY W. KNUEPPEL Henry W. Knueppel, Director	February 27, 2013
/s/ULICE PAYNE, JR. Ulice Payne, Jr., Director	February 27, 2013

/s/MARY ELLEN STANEK Mary Ellen Stanek, Director	February 27, 2013

WISCONSIN ENERGY CORPORATION
(Commission File No. 001-09057)

EXHIBIT INDEX
to
Annual Report on Form 10-K
For the year ended December 31, 2012

The following exhibits are filed or furnished with or incorporated by reference in the report with respect to Wisconsin Energy Corporation. (An asterisk (*) indicates incorporation by reference pursuant to Exchange Act Rule 12b-32.)

Number	Exhibit	
3	Articles of Incorporation and By-laws	
	3.1*	Restated Articles of Incorporation of Wisconsin Energy Corporation, as amended effective May 21, 2012. (Exhibit 3.1 to Wisconsin Energy Corporation's 06/30/12 Form 10-Q.)
	3.2*	Bylaws of Wisconsin Energy Corporation, as amended to May 21, 2012. (Exhibit 3.2 to Wisconsin Energy Corporation's 06/30/12 Form 10-Q.)
4	Instruments defining the rights of security holders, including indentures	
	4.1*	Reference is made to Article III of the Restated Articles of Incorporation and the Bylaws of Wisconsin Energy Corporation. (Exhibits 3.1 and 3.2 herein.)
	4.2*	Replacement Capital Covenant, dated May 11, 2007, by Wisconsin Energy Corporation for the benefit of certain debtholders named therein. (Exhibit 4.2 to Wisconsin Energy Corporation's 05/08/07 Form 8-K.)
	Indentures and Securities Resolutions:	
	4.3*	Indenture for Debt Securities of Wisconsin Electric Power Company (the "Wisconsin Electric Indenture"), dated December 1, 1995. (Exhibit (4)-1 under File No. 1-1245, Wisconsin Electric's 12/31/95 Form 10-K.)
	4.4*	Securities Resolution No. 1 of Wisconsin Electric under the Wisconsin Electric Indenture, dated December 5, 1995. (Exhibit (4)-2 under File No. 1-1245, Wisconsin Electric's 12/31/95 Form 10-K.)
	4.5*	Securities Resolution No. 2 of Wisconsin Electric under the Wisconsin Electric Indenture, dated November 12, 1996. (Exhibit 4.44 to Wisconsin Energy Corporation's 12/31/96 Form 10-K.)
	4.6*	Securities Resolution No. 5 of Wisconsin Electric under the Wisconsin Electric Indenture, dated as of May 1, 2003. (Exhibit 4.47 filed with Post-Effective Amendment No. 1 to Wisconsin Electric's Registration Statement on Form S-3 (File No. 333-101054), filed May 6, 2003.)

4.7*	Securities Resolution No. 7 of Wisconsin Electric under the Wisconsin Electric Indenture, dated as of November 2, 2006. (Exhibit 4.1 to Wisconsin Electric's 11/02/06 Form 8-K.)

Number	Exhibit	
	4.8*	Securities Resolution No. 8 of Wisconsin Electric under the Wisconsin Electric Indenture, dated as of September 25, 2008. (Exhibit 4.1 to Wisconsin Electric's 09/25/08 Form 8-K.)
	4.9*	Securities Resolution No. 9 of Wisconsin Electric under the Wisconsin Electric Indenture, dated as of December 8, 2008. (Exhibit 4.1 to Wisconsin Electric's 12/08/08 Form 8-K.)
	4.10*	Securities Resolution No. 10 of Wisconsin Electric under the Wisconsin Electric Indenture, dated as of December 8, 2009. (Exhibit 4.1 to Wisconsin Electric's 12/08/09 Form 8-K.)
	4.11*	Securities Resolution No. 11 of Wisconsin Electric under the Wisconsin Electric Indenture, dated as of September 7, 2011. (Exhibit 4.1 to Wisconsin Electric's 09/07/11 Form 8-K.)
	4.12*	Securities Resolution No. 12 of Wisconsin Electric Under the Wisconsin Electric Indenture, dated as of December 5, 2012. (Exhibit 4.1 to Wisconsin Electric's 12/05/12 Form 8-K.)
	4.13*	Indenture for Debt Securities of Wisconsin Energy Corporation (the "Wisconsin Energy Indenture"), dated as of March 15, 1999. (Exhibit 4.46 to Wisconsin Energy Corporation's 03/25/99 Form 8-K.)
	4.14*	Securities Resolution No. 4 of Wisconsin Energy under the Wisconsin Energy Indenture, dated as of March 17, 2003. (Exhibit 4.12 filed with Post-Effective Amendment No. 1 to Wisconsin Energy Corporation's Registration Statement on Form S-3 (File No. 333-69592), filed March 20, 2003.)
	4.15*	Securities Resolution No. 5 of Wisconsin Energy under the Wisconsin Energy Indenture, dated as of May 8, 2007. (Exhibit 4.1 to Wisconsin Energy Corporation's 05/08/07 Form 8-K.)
		Certain agreements and instruments with respect to unregistered long-term debt not exceeding 10 percent of the total assets of the Registrant and its subsidiaries on a consolidated basis have been omitted as permitted by related instructions. The Registrant agrees pursuant to Item 601(b)(4) of Regulation S-K to furnish to the Securities and Exchange Commission, upon request, a copy of all such agreements and instruments.
10	Material Contracts	
	10.1*	Wisconsin Energy Corporation Supplemental Pension Plan, effective as of January 1, 2005. (Exhibit 10.9 to Wisconsin Energy Corporation's 12/31/08 Form 10-K.)** See Note.
	10.2*	Service Agreement, dated April 25, 2000, between Wisconsin Electric Power Company and Wisconsin Gas Company (n/k/a Wisconsin Gas LLC). (Exhibit 10.32 to Wisconsin Energy Corporation's 12/31/00 Form 10-K.)
	10.3*	Service Agreement, dated December 29, 2000, between Wisconsin Electric Power Company and American Transmission Company LLC. (Exhibit 10.33 to Wisconsin Energy Corporation's 12/31/00 Form 10-K.)

Number	Exhibit
10.4*	Executive Deferred Compensation Plan of Wisconsin Energy Corporation, as amended and restated as of July 23, 2004 (including amendments approved effective as of November 2, 2005) (the "Legacy EDCP"). (Exhibit 10.2 to Wisconsin Energy Corporation's 09/30/05 Form 10-Q.)** See Note.
10.5*	First Amendment to the Legacy EDCP, effective as of January 1, 2005. (Exhibit 10.12 to Wisconsin Energy Corporation's 12/31/08 Form 10-K.)** See Note.
10.6*	Wisconsin Energy Corporation Executive Deferred Compensation Plan, amended and restated effective as of September 8, 2009. (Exhibit 10.9 to Wisconsin Energy Corporation's 12/31/11 Form 10-K.)** See Note.
10.7*	Directors' Deferred Compensation Plan of Wisconsin Energy Corporation, as amended and restated as of May 1, 2004 (the "Legacy DDCP"). (Exhibit 10.3 to Wisconsin Energy Corporation's 06/30/04 Form 10-Q.)** See Note.
10.8*	First Amendment to the Legacy DDCP, effective as of January 1, 2005. (Exhibit 10.15 to Wisconsin Energy Corporation's 12/31/08 Form 10-K.)** See Note.
10.9	Wisconsin Energy Corporation Directors' Deferred Compensation Plan, effective as of January 1, 2005. (Exhibit 10.16 to Wisconsin Energy Corporation's 12/31/08 Form 10-K.)** See Note.
10.10*	Wisconsin Energy Corporation Death Benefit Only Plan, as amended and restated as of July 22, 2010. (Exhibit 10.1 to Wisconsin Energy Corporation's 09/30/10 Form 10-Q.) ** See Note.
10.11*	Wisconsin Energy Corporation Short-Term Performance Plan, as amended and restated effective as of January 1, 2010. (Exhibit 10.1 to Wisconsin Energy Corporation's 12/03/09 Form 8-K.)** See Note.
10.12*	Wisconsin Energy Corporation Amended and Restated Executive Severance Policy, effective as of January 1, 2008. (Exhibit 10.18 to Wisconsin Energy Corporation's 12/31/08 Form 10-K.)** See Note.
10.13*	Restated Non-Qualified Trust Agreement by and between Wisconsin Energy Corporation and The Northern Trust Company dated February 11, 2004, regarding trust established to provide a source of funds to assist in meeting of the liabilities under various nonqualified deferred compensation plans made between Wisconsin Energy Corporation or its subsidiaries and various plan participants. (Exhibit 10.16 to Wisconsin Energy Corporation's 12/31/07 Form 10-K.)** See Note.
10.14*	Affiliated Interest Agreement (Service Agreement), dated December 12, 2002, by and among Wisconsin Energy Corporation and its affiliates. (Exhibit 10.14 to Wisconsin Energy Corporation's 12/31/02 Form 10-K.)
10.15*	

Amended and Restated Senior Officer Employment and Non-Compete Agreement between Wisconsin Energy Corporation and Gale E. Klappa, dated as of December 29, 2008. (Exhibit 10.25 to Wisconsin Energy Corporation's 12/31/08 Form 10-K.)** See Note.

Number	Exhibit
10.16*	Amended and Restated Senior Officer Employment and Non-Compete Agreement between Wisconsin Energy Corporation and Allen L. Leverett, dated as of December 30, 2008. (Exhibit 10.26 to Wisconsin Energy Corporation's 12/31/08 Form 10-K.)** See Note.
10.17*	Amended and Restated Senior Officer Employment and Non-Compete Agreement between Wisconsin Energy Corporation and Frederick D. Kuester, dated as of December 30, 2008. (Exhibit 10.27 to Wisconsin Energy Corporation's 12/31/08 Form 10-K.)** See Note.
10.18	Consulting Agreement between Wisconsin Energy Corporation and Frederick D. Kuester, dated as of January 7, 2013.** See Note.
10.19*	Terms of Employment for J. Patrick Keyes. (Exhibit 10.1 to Wisconsin Energy Corporation's 09/30/2012 Form 10-Q.)** See Note.
10.20	Letter Agreement by and between Wisconsin Energy Corporation and J. Patrick Keyes, dated as of December 20, 2010.** See Note.
10.21	Amendment to the Letter Agreement by and between Wisconsin Energy Corporation and J. Patrick Keyes, dated as of August 15, 2011.** See Note
10.22*	Terms of Employment for Susan H. Martin. (Exhibit 10.1 to Wisconsin Energy Corporation's 03/31/12 Form 10-Q.)** See Note.
10.23*	Letter Agreement by and between Wisconsin Energy Corporation and James C. Fleming, dated as of November 23, 2005, which became effective January 3, 2006. (Exhibit 10.31 to Wisconsin Energy Corporation's 12/31/05 Form 10-K.)** See Note.
10.24*	Amendment to the Letter Agreement between Wisconsin Energy Corporation and James C. Fleming, dated December 23, 2008. (Exhibit 10.29 to Wisconsin Energy Corporation's 12/31/08 Form 10-K.)** See Note.
10.25*	Amended and Restated Senior Officer, Change in Control, Severance and Non-Compete Agreement between Wisconsin Energy Corporation and Kristine A. Rappé, dated as of December 30, 2008. (Exhibit 10.30 to Wisconsin Energy Corporation's 12/31/08 Form 10-K.)** See Note.
10.26	Separation Agreement and General Release between Wisconsin Energy Corporation and Kristine A. Rappé, effective December 28, 2012.** See Note.
10.27*	Supplemental Pension Benefit Agreement between Wisconsin Energy Corporation and Stephen Dickson, effective May 23, 2001. (Exhibit 10.1 to Wisconsin Energy Corporation's 06/30/01 Form 10-Q.)** See Note.
10.28*	Amendment to the Supplemental Pension Benefit Agreement between Wisconsin Energy Corporation and Stephen Dickson, dated December 29, 2008. (Exhibit 10.32 to Wisconsin Energy Corporation's 12/31/08 Form 10-K.)** See Note.

Number	Exhibit
10.29*	Amended and Restated Non-Compete and Special Severance Tax Protection Agreement between Wisconsin Energy Corporation and Stephen P. Dickson, effective as of January 1, 2008. (Exhibit 10.33 to Wisconsin Energy Corporation's 12/31/08 Form 10-K.)** See Note.
10.30*	Letter Agreement by and between Wisconsin Energy Corporation and Robert Garvin, dated January 31, 2011. (Exhibit 10.1 to Wisconsin Energy Corporation's 03/31/11 Form 10-Q.)** See Note.
10.31*	Letter Agreement by and between Wisconsin Energy Corporation and Joseph Kevin Fletcher, dated as of August 17, 2011. (Exhibit 10.1 to Wisconsin Energy Corporation's 09/30/11 Form 10-Q.)** See Note.
10.32*	2001 Revised forms of award agreements under 1993 Omnibus Stock Incentive Plan for restricted stock awards, incentive stock option awards and non-qualified stock option awards. (Exhibit 10.3 to Wisconsin Energy Corporation's 03/31/01 Form 10-Q.)** See Note.
10.33*	1993 Omnibus Stock Incentive Plan, amended and restated effective as of May 5, 2011, as approved by the stockholders at the 2011 annual meeting of stockholders. (Exhibit 10.1 to Wisconsin Energy Corporation's 06/30/11 Form 10-Q.)** See Note.
10.34*	2005 Terms and Conditions Governing Non-Qualified Stock Option Award under 1993 Omnibus Stock Incentive Plan. (Exhibit 10.1 to Wisconsin Energy Corporation's 12/28/04 Form 8-K.)** See Note.
10.35*	Terms and Conditions Governing Non-Qualified Stock Option Award under the 1993 Omnibus Stock Incentive Plan. (Exhibit 10.1 to Wisconsin Energy Corporation's 09/30/07 Form 10-Q.)** See Note.
10.36*	Terms and Conditions Governing Restricted Stock Awards under the 1993 Omnibus Stock Incentive Plan, approved December 3, 2009. (Exhibit 10.3 to Wisconsin Energy Corporation's 12/03/09 Form 8-K.)** See Note.
10.37*	Terms and Conditions Governing Restricted Stock Awards under the 1993 Omnibus Stock Incentive Plan, approved December 1, 2010. (Exhibit 10.1 to Wisconsin Energy Corporation's 12/01/10 Form 8-K.)** See Note.
10.38*	Wisconsin Energy Corporation Terms and Conditions Governing Director Restricted Stock Award under the 1993 Omnibus Stock Incentive Plan, amended and restated effective May 5, 2011. (Exhibit 10.1 to Wisconsin Energy Corporation's 01/19/12 Form 8-K.)** See Note.
10.39*	Wisconsin Energy Corporation Performance Unit Plan, amended and restated effective as of January 1, 2010. (Exhibit 10.2 to Wisconsin Energy Corporation's 12/03/09 Form 8-K.)** See Note.
10.40*	Form of Award of Performance Units under the Wisconsin Energy Corporation Performance Unit Plan. (Exhibit 10.2 to Wisconsin Energy Corporation's 12/06/04 Form 8-K.)** See Note.

Number	Exhibit	
	10.41*	Port Washington I Facility Lease Agreement between Port Washington Generating Station, LLC, as Lessor, and Wisconsin Electric Power Company, as Lessee, dated as of May 28, 2003. (Exhibit 10.7 to Wisconsin Electric Power Company's 06/30/03 Form 10-Q (File No. 001-01245).)
	10.42*	Port Washington II Facility Lease Agreement between Port Washington Generating Station, LLC, as Lessor, and Wisconsin Electric Power Company, as Lessee, dated as of May 28, 2003. (Exhibit 10.8 to Wisconsin Electric Power Company's 06/30/03 Form 10-Q (File No. 001-01245).)
	10.43*	Elm Road I Facility Lease Agreement between Elm Road Generating Station Supercritical, LLC, as Lessor, and Wisconsin Electric Power Company, as Lessee, dated as of November 9, 2004. (Exhibit 10.56 to Wisconsin Energy Corporation's 12/31/04 Form 10-K.)
	10.44*	Elm Road II Facility Lease Agreement between Elm Road Generating Station Supercritical, LLC, as Lessor, and Wisconsin Electric Power Company, as Lessee, dated as of November 9, 2004. (Exhibit 10.57 to Wisconsin Energy Corporation's 12/31/04 Form 10-K.)
	10.45*	Point Beach Nuclear Plant Power Purchase Agreement between FPL Energy Point Beach, LLC and Wisconsin Electric Power Company, dated as of December 19, 2006 (the "PPA"). (Exhibit 10.1 to Wisconsin Energy Corporation's 03/31/08 Form 10-Q.)
	10.46*	Letter Agreement between Wisconsin Electric Power Company and FPL Energy Point Beach, LLC dated October 31, 2007, which amends the PPA. (Exhibit 10.45 to Wisconsin Energy Corporation's 12/31/07 Form 10-K.)
	Note: Two asterisks (**) identify management contracts and executive compensation plans or arrangements required to be filed as exhibits pursuant to Item 15(b) of Form 10-K.	
21	Subsidiaries of the registrant	
	21.1	Subsidiaries of Wisconsin Energy Corporation.
23	Consents of experts and counsel	
	23.1	Deloitte & Touche LLP -- Milwaukee, WI, Consent of Independent Registered Public Accounting Firm.
31	Rule 13a-14(a) / 15d-14(a) Certifications	
	31.1	Certification Pursuant to Rule 13a-14(a) or 15d-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
	31.2	Certification Pursuant to Rule 13a-14(a) or 15d-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

Number	Exhibit	
32	Section 1350 Certifications	
	32.1	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
	32.2	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101	Interactive Data File	