WISCONSIN ENERGY CORP
Form 10-K
February 27, 2014

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, 2013

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. [X]

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 $9.3 billion based upon the reported closing price of such securities as of June 30, 2013.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date (January 31, 2014):

Common Stock, $.01 Par Value,	225,946,296 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, 2014, are incorporated by reference into Part III hereof.

2013 Form 10-K

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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	
MCPP	Milwaukee County Power Plant
OC 1	Oak Creek expansion Unit 1
OC 2	Oak Creek expansion Unit 2
PIPP	Presque Isle Power Plant
PSGS	Paris 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
DATC	Duke-American Transmission Company
ERGSS	Elm Road Generating Station Supercritical, LLC
WECC	Wisconsin Energy Capital Corporation
Wispark	Wispark LLC
Wisvest	Wisvest LLC
Federal and State Regulatory Agencies	
DOE	United States Department of Energy
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
IRS	Internal Revenue Service
MDEQ	Michigan Department of Environmental Quality
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

NOV Notice of Violation

5 Wisconsin Energy Corporation

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:

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
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	Midcontinent Independent System Operator, Inc.
MISO Energy Markets	MISO Energy and Operating Reserves Market
Moody's	Moody's Investor Service
NYMEX	New York Mercantile Exchange
OTC	Over-the-Counter
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
S&P	Standard & Poor's Ratings Services
SSR	System Support Resource
Treasury Grant	Section 1603 Renewable Energy Treasury Grant
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)
GWh	Gigawatt-hour(s) (One GWh equals one thousand MWh)
kW	Kilowatt(s) (One kW equals one thousand Watts)
kWh	Kilowatt-hour(s)
MW	Megawatt(s) (One MW equals one million Watts)
MWh	Megawatt-hour(s)
Watt	A measure of power production or usage

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:

Accounting Terms	
AFUDC	Allowance for Funds Used During Construction
ARO	Asset Retirement Obligation
ASU	Accounting Standards Update
CWIP	Construction Work in Progress
GAAP	Generally Accepted Accounting Principles
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, retail sales and customer growth, rate actions and related filings with the appropriate regulatory authorities, current and proposed environmental regulations and other regulatory matters and related estimated expenditures, on-going legal proceedings, dividend payout ratios, projections related to the pension and other post-retirement benefit plans, fuel costs, sources of electric energy supply, coal and gas deliveries, remediation costs, 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 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; or collective bargaining agreements with union employees or work stoppages.

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

- Timing, resolution and impact of rate cases and negotiations, including recovery of costs associated with environmental compliance, renewable generation, transmission service, distribution system upgrades, fuel and the Midcontinent Independent System Operator, Inc. (MISO) Energy Markets, as well as any costs incurred as a result of customers moving to an alternative electric supplier.

- Increased competition in our electric and gas markets, including retail choice and alternative electric suppliers, and continued industry consolidation.

- Our ability to mitigate the impact of Michigan customers switching to an alternative electric supplier, including the receipt of adequate System Support Resource (SSR) payments.

- The ability to control costs and avoid construction delays during the development and construction of new electric generation facilities, as well as upgrades to our generation fleet and 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; regulatory initiatives regarding deregulation and restructuring of the electric and/or gas utility industry; 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 cyber security threats; the regulatory approval process for new generation and transmission facilities and new pipeline construction; changes in environmental, federal and state energy, tax and other laws and regulations to which we are subject; changes in allocation of energy assistance, including state public benefits funds; changes in the application or enforcement 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 Federal Energy Regulatory Commission (FERC) matters and Internal Revenue Service (IRS) and state tax 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.

- Inflation rates.

- 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, as well as the ability of ATC and the Duke-American Transmission Company (DATC) to obtain the required approvals for their transmission projects.

- 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.

- Advances in technology 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 cannot be assured to be completed or beneficial to 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 factors discussed elsewhere in this report and that may be disclosed from time to time in our Securities and Exchange Commission (SEC) filings or in other publicly disseminated written documents.

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

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 1,128,300 electric customers in Wisconsin and the Upper Peninsula of Michigan. We Energies serves approximately 1,079,800 gas customers in Wisconsin and approximately 445 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 Power the Future (PTF) strategy. All four of the plants constructed as part of 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 O -- 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, including distribution sales to those customers who switched to an alternative electric supplier, totaled approximately 33.0 million MWh during 2013 and approximately 30.3 million MWh during 2012. We had approximately 1,128,300 electric customers as of December 31, 2013 and 1,125,700 electric customers as of December 31, 2012.

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 slightly declining retail sales in 2013 as positive customer growth was more than offset by reduced use per customer. 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 about 0.5% over the next five years. 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 paper, foundry, food products and machinery production, as well as to large retail chains.

Prior to September 2013, our largest retail electric customers were two iron ore mines located in the Upper Peninsula of Michigan. The combined electric energy sales to the two mines accounted for 3.7% and 6.6% of our total electric utility energy sales during 2013 and 2012, respectively.

The two iron ore mines, which we served on an interruptible tariff rate, switched to an alternative electric supplier effective September 1, 2013. For additional information, see Factors Affecting Results, Liquidity and Capital Resources -- Industry Restructuring and Competition in Item 7.

Sales to Wholesale Customers: During 2013, we sold wholesale electric power to two Regional Transmission Organizations (RTOs), five rural cooperatives, and four municipal joint action agencies located in the states of Wisconsin and Michigan. Our wholesale electric energy sales were also made to eight other public utilities and power marketers throughout the region under rates approved by FERC. Wholesale sales accounted for approximately 19.7% of our total electric energy sales and 8.7% of total electric operating revenues during 2013, compared with 10.6% of total electric energy sales and 6.2% of total electric operating revenues during 2012.

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 MISO calculated planning reserve margin during 2013 and expect to have adequate capacity to meet the planning reserve margin requirements during 2014. For additional information, see Factors Affecting Results, Liquidity and Capital Resources in Item 7.

Competition

Retail electric customers in Wisconsin currently do not have the ability to choose their electric supplier. It is uncertain when, if ever, retail access might be implemented in Wisconsin. However, Wisconsin Electric attempts to attract new customers into our service territory to increase sales in order to allocate the recovery of our costs among a larger customer base. The regulated energy industry continues to experience significant structural changes, which could eventually lead to increased competition 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. See Factors Affecting Results, Liquidity and Capital Resources - Industry Restructuring and Competition - Restructuring in Michigan, for a discussion of the impact of customers switching to an alternative electric supplier in Michigan on our electric sales.

We compete with other utilities for sales to municipalities and cooperatives. We also compete with other utilities and marketers in the wholesale electric business. Our wholesale sales are impacted by availability, wholesale electric prices, market conditions and fuel costs.

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)		
	2013	2012	2011
Coal	3,822	3,828	3,904
Natural Gas - Combined Cycle	1,082	1,090	1,090
Natural Gas/Oil - Peaking Units (b)	962	962	967
Renewables (c)	155	107	80
Total	6,021	5,987	6,041

(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 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.

(c) Includes hydroelectric, biomass 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, 2013, as well as an estimate for 2014:

	Estimate	Actual					
	2014		2013		2012		2011	
Coal	56.0	%	53.6	%	43.0	%	54.2	%
Natural Gas - Combined Cycle	6.6	%	10.1	%	15.9	%	6.6	%
Renewables	4.1	%	3.3	%	3.0	%	2.0	%
Natural Gas/Oil-Peaking Units	0.1	%	0.2	%	0.7	%	0.1	%
Net Generation	66.8	%	67.2	%	62.6	%	62.9	%
Purchased Power	33.2	%	32.8	%	37.4	%	37.1	%
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:

	2013	2012	2011
Coal	$27.97	$30.71	$29.78
Natural Gas - Combined Cycle	$32.22	$23.62	$38.02
Natural Gas/Oil - Peaking Units	$83.95	$53.40	$119.83
Purchased Power	$43.74	$41.92	$42.79

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 changing 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 2014, 94% of our projected coal requirements of 10.8 million tons are under contracts which are not tied to 2014 market pricing fluctuations. At the end of 2013, our coal-fired generation consisted of six operating plants with a dependable capability of approximately 3,822 MW.

The annual tonnage amounts contracted for 2014 through 2016 are as follows:

Year	Annual Tonnage (Thousands)
2014	10,157
2015	7,180
2016	3,920

These figures exclude the Oak Creek expansion projected coal requirements and allocated commitments of the plant's co-owners.

Coal Deliveries: Approximately 98% of our 2014 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 (PIPP) 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.

Wolverine Joint Ownership Agreement: In November 2012, we entered into a joint ownership agreement with Wolverine Power Supply Cooperative, Inc. (Wolverine) regarding PIPP, whereby Wolverine would pay for the installation of the air quality control systems at PIPP and receive a minority undivided ownership interest in the plant in return.

However, in light of the recent loss of retail electric customers in Michigan due to that state's alternative electric supplier program (see Factors Affecting Results, Liquidity and Capital Resources -- Industry Restructuring and Competition -- Restructuring in Michigan in Item 7), the two parties decided to terminate the joint venture agreement in December 2013. We are currently evaluating options for the long-term future of PIPP.

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 1,864 MW as of December 31, 2013.

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, as well as 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 PIPP, 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, 2013. 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 39 MW as of December 31, 2013. 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 have four wind sites, consisting of 200 turbines with an installed capacity of 338 MW and a dependable capability of 66 MW.

Biomass: We constructed a biomass-fueled power plant at Domtar Corporation's Rothschild, Wisconsin paper mill site that went into commercial operation on November 8, 2013. Wood waste and wood shavings are used to produce approximately 50 MW of renewable electricity and also support Domtar's sustainable papermaking operations. The final cost of completing this project was $269.0 million, excluding Allowance for Funds Used During Construction (AFUDC).

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, 2013 with unaffiliated parties for the next five years:

Year	MW
2014	1,267
2015	1,267
2016	1,267
2017	1,267
2018	1,267

The above commitments include approximately 1,030 MW per year related to the Point Beach long-term power purchase agreement. The balance of these purchased power commitments is an arrangement where we buy power at a price determined monthly based on a formula tied to the gas price index.

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, Illinois and Minnesota. 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, 2013 and 2012. For additional information, see Note P -- 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. DATC has proposed nine new transmission lines, located in five Midwestern states, to support MISO's and PJM Interconnection's transmission expansion plans. These projects are subject to the receipt of all necessary approvals. In addition, in April 2013, DATC acquired a 72% interest in California's Path 15 transmission line.

MISO: In connection with its status as a FERC approved RTO, MISO developed bid-based energy markets. In January 2009, MISO commenced the Energy and Operating Reserves Markets, which includes the bid-based energy markets and the ancillary services market. In 2013, MISO expanded its footprint to include entities in Mississippi, Arkansas, Texas and Missouri. This new region is referred to as MISO South. We are participants in the Central region. We do not expect these changes to have a material impact on our allocation of MISO costs. For further information on MISO and the MISO Energy Markets, see Factors Affecting Results, Liquidity and Capital Resources -- Industry Restructuring and Competition - Electric Transmission, Capacity 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	2013	2012	2011	2010	2009
Operating Revenues (Millions)					
Residential	$1,208.6	$1,163.9	$1,159.2	$1,114.3	$977.6
Small Commercial/Industrial	1,048.0	1,013.6	1,006.9	922.2	860.3
Large Commercial/Industrial	711.9	744.3	763.7	677.1	599.4
Other - Retail	23.4	22.8	22.9	21.9	21.2
Total Retail Revenues	2,991.9	2,944.6	2,952.7	2,735.5	2,458.5
Wholesale - Other	143.7	144.4	154.0	134.6	116.7
Resale - Utilities	143.2	53.4	69.5	40.4	47.5
Other Operating Revenues	28.4	51.5	35.1	25.8	62.3
Total	3,307.2	3,193.9	3,211.3	2,936.3	2,685.0
Electric Customer Choice (a)	1.5	—	—	—	—
Total Operating Revenues, including customer choice	$3,308.7	$3,193.9	$3,211.3	$2,936.3	$2,685.0
MWh Sales (Thousands)					
Residential	8,141.9	8,317.7	8,278.5	8,426.3	7,949.3
Small Commercial/Industrial	8,860.4	8,860.0	8,795.8	8,823.3	8,571.6
Large Commercial/Industrial	8,673.4	9,710.7	9,992.2	9,961.5	9,140.3
Other - Retail	152.3	154.8	153.6	155.3	156.5
Total Retail Sales	25,828.0	27,043.2	27,220.1	27,366.4	25,817.7
Wholesale - Other	1,953.5	1,566.6	2,024.8	2,004.6	1,529.4
Resale - Utilities	4,382.7	1,642.4	2,065.7	1,103.8	1,548.9
Total Electric Sales	32,164.2	30,252.2	31,310.6	30,474.8	28,896.0
Electric Customer Choice (a)	813.0	—	—	—	—
Total MWh Delivered	32,977.2	30,252.2	31,310.6	30,474.8	28,896.0
Customers - End of Year (Thousands)					
Residential	1,010.5	1,008.2	1,005.5	1,003.6	1,001.2
Small Commercial/Industrial	114.6	114.3	113.8	113.5	113.1
Large Commercial/Industrial	0.7	0.7	0.7	0.7	0.7
Other	2.5	2.5	2.5	2.4	2.4
Total Customers	1,128.3	1,125.7	1,122.5	1,120.2	1,117.4
Customers - Average (Thousands)	1,126.9	1,123.8	1,121.0	1,118.7	1,115.5
Degree Days (b)					
Heating (6,580 Normal)	7,233	5,704	6,633	6,183	6,825
Cooling (730 Normal)	688	1,041	793	944	475

(a)

Represents distribution sales for customers who have purchased power from an alternative electric supplier in Michigan.

(b) 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 2,442.8 million therms during 2013, a 9.9% increase compared with 2012. As of December 31, 2013, we were transporting gas for approximately 1,700 customers who purchased gas directly from other suppliers. Transported gas accounted for approximately 43.1% of the total volumes delivered during 2013, 51.3% during 2012 and 41.8% during 2011. We had approximately 1,079,800 and 1,074,000 gas customers as of December 31, 2013 and 2012, respectively. Our peak daily send-out during 2013 was 1,701,421 Dth on January 21, 2013.

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 paper, food products and fabricated metal products. Fuel used for Wisconsin Electric's electric generation represents our largest transportation customer. Gas therms delivered to Wisconsin Electric for electric generation represents 10.4%, 17.2% and 8.3% of the total volumes delivered during 2013, 2012 and 2011, respectively.

Gas Deliveries Growth: We currently forecast total retail therm deliveries (excluding natural gas deliveries for generation) to be between flat and 0.5% growth over the five-year period ending December 31, 2018, as we expect new customer additions to increase and offset an anticipated slight decline in 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 filed an application with the PSCW seeking approval to construct a new natural gas lateral on March 28, 2013. The anticipated cost of the initial phase of this project is approximately $150 million to $170 million, excluding AFUDC.

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 firm customers to choose an alternative gas commodity supplier may be removed such that we begin to face competition for the sale of gas to those 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: Pipeline long-line and storage capacity and gas supplies under contract can be resold in secondary markets. Local distribution companies, like Wisconsin Electric and Wisconsin Gas, 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. The secondary markets facilitate 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 2013, we continued to participate in the secondary markets. 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% of 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	2013	2012	2011	2010	2009
Operating Revenues (Millions)					
Residential	$712.6	$612.0	$737.4	$754.2	$856.6
Commercial/Industrial	347.2	289.7	369.9	373.1	442.9
Interruptible	8.9	7.3	9.4	11.8	11.9
Total Retail Gas Sales	1,068.7	909.0	1,116.7	1,139.1	1,311.4
Transported Gas	50.8	49.4	49.2	48.0	44.8
Other Operating Revenues	(5.8)	4.2	15.3	3.1	11.7
Total Operating Revenues	$1,113.7	$962.6	$1,181.2	$1,190.2	$1,367.9
Therms Delivered (Millions)					
Residential	872.0	676.4	776.8	741.2	803.4
Commercial/Industrial	499.9	390.6	461.7	429.6	479.4
Interruptible	18.1	14.6	16.0	19.4	19.1
Total Retail Gas Sales	1,390.0	1,081.6	1,254.5	1,190.2	1,301.9
Transported Gas	1,052.8	1,140.4	899.6	914.9	882.0
Total Therms Delivered	2,442.8	2,222.0	2,154.1	2,105.1	2,183.9
Customers - End of Year (Thousands)					
Residential	985.7	980.3	975.2	971.7	967.7
Commercial/Industrial	92.3	92.0	91.5	91.3	91.1
Interruptible	0.1	0.1	0.1	0.1	0.1
Transported Gas	1.7	1.6	1.4	1.4	1.3
Total Customers	1,079.8	1,074.0	1,068.2	1,064.5	1,060.2
Customers - Average (Thousands)	1,074.9	1,068.9	1,064.1	1,060.2	1,055.6
Degree Days (a)					
Heating (6,580 Normal)	7,233	5,704	6,633	6,183	6,825

(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 2013, the steam utility had $39.6 million of operating revenues from the sale of 2,750 million pounds of steam compared with $34.3 million of operating revenues from the sale of 2,449 million pounds of steam during 2012. As of December 31, 2013 and 2012, steam was used by approximately 445 customers and 460 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, 2013, 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 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, 2013, 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, 2013. 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, 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, 2013.

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. Almost all of 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, 2013:

	2013 Amount	Percent		2012 Amount	Percent		2011 Amount	Percent	
	(Millions of Dollars)								
Electric									
Wisconsin - Retail	$2,874.8	86.9	%	$2,808.4	87.9	%	$2,775.8	86.4	%
Michigan - Retail	147.0	4.4	%	187.8	5.9	%	212.0	6.6	%
FERC - Wholesale	286.9	8.7	%	197.7	6.2	%	223.5	7.0	%
Total	3,308.7	100.0	%	3,193.9	100.0	%	3,211.3	100.0	%
Gas - Wisconsin - Retail	1,113.7	100.0	%	962.6	100.0	%	1,181.2	100.0	%
Steam - Wisconsin - Retail	39.6	100.0	%	34.3	100.0	%	39.0	100.0	%
Total Utility Operating Revenues	$4,462.0			$4,190.8			$4,431.5		

The percentage of revenues regulated by the MPSC is likely to decline in the future.

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 (MDEQ) 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%. As of December 31, 2013, 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 2013. The funding required by Act 141 for 2014 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. We are currently in compliance with this requirement. 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 our renewable portfolio, see Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters - Renewables, Efficiency and Conservation 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 -- Capital Requirements 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 Q -- 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 $24.7 million in 2013 compared with $64.1 million in 2012. Expenditures incurred during 2013 and 2012 primarily included costs associated with the installation of pollution abatement facilities at Wisconsin Electric's power plants. These expenditures are expected to be approximately $2.3 million during 2014. Operation, maintenance and depreciation expenses for fly ash removal equipment and other environmental protection systems were approximately $92.9 million and $82.6 million during 2013 and 2012, 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 near the sites, located in the Village of Caledonia and the City of Oak Creek, Wisconsin, was found to contain levels of molybdenum above the allowable limit prompting Wisconsin Electric to begin investigation in 2009 for the source of the molybdenum. Our study indicates that the groundwater impacts are 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 in 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 further supporting our position that regional ground water impacts are not a result of coal ash management activities at the Oak Creek site. The Wisconsin Department of Health Services has since increased the allowable limit for molybdenum in groundwater, and the WDNR sent a letter to residents with private wells that exceeded the earlier limit with information about the change.

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, 2013, we had the following number of employees:

	Total Employees	Represented Employees
Utility Energy Segment		
Wisconsin Electric	3,893	2,517
Wisconsin Gas	407	280
Total	4,300	2,797
Non-Utility Energy Segment	—	—
Other	3	—
Total Employees	4,303	2,797

The employees represented under labor agreements were with the following bargaining units as of December 31, 2013:

	Number of Employees	Expiration Date of Current Labor Agreement
Wisconsin Electric		
Local 2150 of International Brotherhood of Electrical Workers	1,730	August 15, 2017
Local 420 of International Union of Operating Engineers	539	September 30, 2017
Local 2006 Unit 1 of United Steel Workers	142	April 30, 2017
Local 510 of International Brotherhood of Electrical Workers	106	October 31, 2016
Total Wisconsin Electric	2,517	
Wisconsin Gas		
Local 2150 of International Brotherhood of Electrical Workers	85	August 15, 2017
Local 2006 Unit 1 of United Steel Workers	192	April 30, 2017
Local 2006 Unit 3 of United Steel Workers	3	February 29, 2016
Total Wisconsin Gas	280	
Total Represented Employees	2,797	

ITEM 1A. RISK FACTORS

We are subject to a variety of risks, many of which are beyond our control, that may adversely affect our business, financial condition and results of operations. You should carefully consider the following risk factors, as well as the other information included in this report and other documents filed by us with the SEC from time to time, when making an investment decision.

Risks Related to Legislation and Regulation

Our business is significantly impacted by governmental regulation.

We are subject to significant state, local and federal governmental regulation. We are subject to regulation by the PSCW of 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 regulation by the MPSC of various matters associated with retail electric service in the state of Michigan, except 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 accounting, 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.

The rates we are allowed to charge our customers for electric, natural gas and steam services have the most significant impact on our financial condition, results of operations and liquidity. Within our regulated energy segment, approximately 87% of our 2013 electric revenues were regulated by the PSCW, 4% were regulated by the MPSC and the balance of our electric revenues were regulated by the FERC. All of our natural gas and steam revenues are regulated by the PSCW. Rate regulation is based on providing an opportunity to recover prudently incurred costs and earn a reasonable rate of return on invested capital. However, our ability to obtain rate adjustments in the future is dependent on regulatory action and there is no assurance that our regulators will consider all of our costs to have been prudently incurred. In addition, our rate proceedings may not always result in rates that fully recover our costs or provide for a reasonable return on equity. We defer certain costs and revenues as regulatory assets and liabilities for future recovery or refund to customers, as authorized by our regulators. Future recovery of regulatory assets is not assured, and is subject to review and approval by our regulators. If recovery of regulatory assets is not approved or is no longer deemed probable, these costs would be charged to income in the current period and could have a material adverse impact on our financial results.

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.

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), Sulfur Dioxide (SO_2), Nitrogen Oxide (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.

The EPA has adopted and is in the process of implementing regulations governing the emission of NO_x, SO_2, fine particulate matter ($PM_{2.5}$), mercury and other air pollutants under the Clean Air Act (CAA) through the National Ambient Air Quality Standards (NAAQS), the Mercury and Air Toxics Standards (MATS) rule and other air quality regulations. In addition, the EPA has proposed rules governing cooling water intake structures at our power plants and revisions to the effluent guidelines for steam electric generating plants under the Clean Water Act (CWA). The EPA also 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; however, the EPA successfully petitioned the United States Supreme Court, who heard the case in December 2013. A decision is expected by June 2014. Therefore, there is still substantial uncertainty as to what capital expenditures may ultimately be required to comply with these regulations.

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 expect that additional environmental controls will be required at PIPP to meet the new environmental standards, and are currently analyzing several environmental compliance options.

In addition, 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 $65 million and $70 million, excluding AFUDC. 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 laws and 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 WDNR has issued a Notice of Violation (NOV) to Wisconsin Electric alleging violations of certain environmental rules at our Paris Generating Station (PSGS). An adverse outcome in these matters could require capital expenditures that cannot be determined at this time and could possibly require payment of 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. Further, increased costs recovered through rates could contribute to reduced demand for electricity, which could adversely affect our results of

operations, cash flows and financial condition.

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.

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

The regulation of greenhouse gas emissions continues to be a top priority for the President's administration. In June 2013, the President issued a presidential memorandum instructing the EPA to, among other things, issue rules pertaining to greenhouse gas emissions from both new and existing 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. The EPA is pursuing regulation of greenhouse gas emissions using its existing authority under the CAA. In September 2013, the EPA withdrew its 2012 proposed New Source Performance Standards greenhouse gas emissions rule, and issued new proposed rules with greenhouse gas limits for new fossil fueled power plants. The rule would not apply to certain natural gas fueled peaking plants, biomass units or oil fueled stationary combustion turbines. Based upon currently available technology and the emission limits in the proposed rule, we believe that this rule, if promulgated, would effectively prohibit new conventional coal-fired power plants.

With respect to existing generating units, the EPA has indicated that it intends to issue a proposed rule in June 2014, a final rule by June 2015 and require State Implementation Plans (SIPs) to be submitted by June 30, 2016. Any such regulations may impact how we operate our existing facilities, particularly our fossil fueled power plants and new biomass facility, and could have a material adverse impact on our financial condition.

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 legislation, regulation or order that requires a reduction in greenhouse gas emissions or that cost recovery will not be delayed or otherwise conditioned. Any legislation or regulation that may be adopted, either at the federal or state level, 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 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 EPA could take action on this matter by the end of 2014.

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 and enforced by the FERC. 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. While Wisconsin Electric passed the cybersecurity and operational audits mandated by the North American Electric Reliability Corporation in 2013, if it were ever found to be in noncompliance with the mandatory reliability standards it could be subject to sanctions, including substantial monetary penalties.

Energy conservation and rate increases could negatively impact financial results.

Customers could voluntarily reduce their consumption of electricity, natural gas and steam in response to decreases in their disposable income, increases in energy prices and/or individual conservation efforts. In addition, 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.

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 generally may not exceed 25% of the assets of all public utility affiliates in the system, subject to certain exceptions.

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 the Operation of Our Business

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; terrorist attacks; cyber security threats; 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.

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.

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

We expect to spend an aggregate of between $3.2 billion and $3.5 billion during the period 2014 to 2018 on capital investments in our utility and non-utility energy business. These types of construction projects are subject to many of the 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; potential legal challenges; changes in applicable law or regulations; other governmental actions; and events in the global economy.

Certain of these projects require the approval of our regulators. In the event we receive approval, total costs of a project 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 additional costs in rates.

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 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.

Advances in technology could make our electric generating facilities less competitive.

We generate power at central station power plants to achieve economies of scale and produce power at a competitive cost. There are distributed generation technologies that produce power, including fuel cells, microturbines, wind turbines and solar cells, which have become more cost competitive. It is possible that advances in technology will continue to reduce the costs of these alternative methods of producing power to a level that is competitive with that of central station power electric production. If these technologies became cost competitive and achieved economies of scale, our market share could be eroded, and the value of our generating facilities could be reduced. Advances in technology could also change the channels through which our electric customers purchase or use power, which could reduce our sales and revenues or increase our expenses.

Under our current rate structure, widespread adoption of distributed generation by our electric customers could increase the cost of service for our remaining customers. Increases in our rates could contribute to slower than anticipated customer growth and reduced demand for electricity, which could have an adverse impact on our financial condition, results of operations and cash flows.

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. At this time, we are not aware of any cyber intrusion or security breach of our systems.

Internet-based attacks on critical U.S. energy infrastructure are occurring with more frequency. In February 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 being developed jointly by the government and industry.

We continue to strengthen our electronic systems. However, as cyber attacks become more sophisticated, 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.

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

As a holding company with no operations of our own, 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.

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.

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 unique technical skill sets. 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.

Failure of a counterparty to one of our power purchase agreements could have an adverse impact on our results of operations.

We have entered into several power purchase agreements with non-affiliated companies, and continue to look for additional opportunities to enter into these agreements. Currently, sales through power purchase agreements are responsible for approximately 4.5% of our electric revenues. Revenues are dependent on the continued performance by the purchasers of their obligations under the power purchase agreements. Although we have a comprehensive credit evaluation process and contractual protections, it is possible that one or more purchasers could fail to perform their obligations under the power purchase agreements. If this were to occur, we would expect that any operating and other costs that were initially allocated to a defaulting customer's power purchase agreement would be reallocated among our retail customers. To the extent there is any regulatory lag to adjust rates, a customer default under a power purchase agreement could have a negative impact on our results of operations and cash flows.

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.

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, changes in tax policy, war or the threat of war, 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 expect to continue experiencing electric sales below historical trends.

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.

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. Under Michigan law, our retail customers may choose an alternative electric supplier to provide power supply service. The law limits customer choice to 10% of our Michigan retail load. The two iron ore mines are excluded from this cap. When a customer switches to an alternative electric supplier, we continue to provide distribution and customer service functions for the customer.

The mines, which we served on an interruptible tariff rate, switched to an alternative electric supplier effective September 1, 2013. In addition, other smaller retail customers have switched to an alternative electric supplier. Sales to these customers, including the mines, totaled 2,173.6 GWh, or 7.6% of our retail electric sales for the year ended December 31, 2012. Previously, the owner of the mines announced that they would shut down the Empire mine by the end of 2014 or beginning of 2015. We negotiated an SSR agreement with MISO and took other steps to mitigate the loss of these sales. Although the financial impact in future periods is uncertain, we currently estimate that these losses will not have a material impact on our consolidated financial statements in 2014.

FERC continues to support the existing RTOs that affect the structure of the wholesale market within these 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.

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 and could adversely impact our collection of accounts receivable.

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 generally carry sufficient coal inventory at our generating facilities to mitigate an interruption or decline in supply, there can be no assurance that the inventory will be adequate to fully mitigate all potential reductions in supply. 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 or that we will be able to take delivery of all the coal volume contracted for. The suppliers under these agreements may experience financial or operational problems that inhibit their ability to fulfill their obligations to us, or we may experience operational problems or constraints that prevent us from taking delivery. 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, demand for coal can impact its availability and cost. If we are unable to obtain our coal requirements under our coal supply and transportation contracts, we may be required to purchase coal at higher prices, or we may be forced to reduce generation at our coal units and replace this lost generation through additional power purchases in the MISO market. There is no guarantee that we would be able to fully recover any increased costs in rates.

Our electric generation frequently exceeds our customer load. When this occurs, we generally sell the excess generation into the MISO market. If we are unable to run our lower cost units we may lose the ability to engage in these opportunity sales, which may adversely affect our 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.

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 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. 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 for which we are not fully insured or that are not covered by insurance at all could materially adversely affect our results of operations, cash flows and financial position.

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, 2013, we owned the following generating assets:

Name	Fuel	No. of Generating Units	Dependable Capability In MW (a)
Coal-Fired Plants			
South Oak Creek	Coal	4	990
Oak Creek Expansion	Coal	2	1,057
Presque Isle	Coal	5	344
Pleasant Prairie	Coal	2	1,188
Valley	Coal	2	236
Milwaukee County	Coal	3	7
Total Coal-Fired Plants		18	3,822
Natural Gas-Fired Plants			
Port Washington Generating Station	Gas	2	1,082
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	—
Total Natural Gas-Fired Plants		17	2,044
Renewables			
Hydro Plants (13 in number)		33	39
Rothschild Biomass Plant	Biomass	1	50
Byron Wind Turbines	Wind	2	—
Blue Sky Green Field	Wind	88	29
Glacier Hills	Wind	90	32
Montfort Wind Energy Center	Wind	20	5
Total Renewables		234	155
Total System		269	6,021

(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. Dependable capability for the wind sites is determined based on a capacity factor of approximately 20%.

As of December 31, 2013, we operated approximately 21,511 pole-miles of overhead distribution lines and 24,086 miles of underground distribution cable, as well as approximately 350 distribution substations and 290,999 line transformers.

As of December 31, 2013, our gas distribution system included approximately 20,967 miles of distribution and transmission mains connected at 181 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, 2013, the combined steam systems supplied by the VAPP and Milwaukee County Power Plant consisted of approximately 42 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.

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 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 Q -- Commitments and Contingencies in the Notes to Consolidated Financial Statements.

Edgewater Generating Unit 5: In December 2009, the EPA issued a NOV concerning several coal-fired power plants owned and operated by Wisconsin Power and Light Company (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. Although Wisconsin Electric sold its interest to WPL in March 2011, it retained its share of liability related to the NOV.

In April 2013, a complaint and consent decree were simultaneously lodged with the court in United States v. Wisconsin Power and Light Company, Madison Gas and Electric Company, Wisconsin Electric Power Company and Wisconsin Public Service Corporation, Case No. 13-cv-00266. The consent decree was entered by the court in June 2013, and resolved all allegations in the NOV related to Edgewater 5 and the other coal fired power plants owned and operated by WPL, as well as air permitting and opacity violations alleged by Sierra Club against WPL. Our share of the financial obligation associated with this consent decree was immaterial. This matter was fully closed when the consent decree was terminated as to Wisconsin Electric on October 1, 2013.

See Environmental Compliance in Item 1 and Environmental Matters, Manufactured Gas Plant Sites, and Coal Combustion Product Landfill Sites in Note Q -- 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

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, 2013 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 63.

- Wisconsin Energy -- Chairman of the Board and Chief Executive Officer since May 2004. President from April 2003 to July 2013.
- 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 53.

- 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 55.

- 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 47.

- 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 48.

- 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 2001 to March 2011.

Allen L. Leverett. Age 47.

- Wisconsin Energy -- President since August 2013. Executive Vice President from May 2004 to July 2013. 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 61.

- 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.

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, 2013, based upon the number of Wisconsin Energy Corporation stockholder accounts (including accounts in our dividend reinvestment and stock purchase plan), we had approximately 39,755 registered stockholders.

COMMON STOCK LISTING AND TRADING

Our common stock is listed on the New York Stock Exchange under the ticker symbol "WEC."

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.

In January 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, the Board increased our quarterly dividend to $0.34 per share effective with the first quarter of 2013 dividend payment. On July 18, 2013, the Board of Directors increased our quarterly dividend to $0.3825 per share effective with the third quarter of 2013 dividend payment.

On January 16, 2014, the Board of Directors increased the quarterly dividend to $0.39 per share effective with the first quarter of 2014 dividend payment, which would result in annual dividends of $1.56 per share. In addition, the Board affirmed our dividend policy that targets a dividend payout ratio of 65-70% in 2017.

Range of Wisconsin Energy Common Stock Prices and Dividends:

	2013			2012		
Quarter	High	Low	Dividend	High	Low	Dividend
First	$42.98	$37.03	$0.3400	$35.35	$33.62	$0.30
Second	$45.00	$39.04	0.3400	$40.00	$34.54	0.30
Third	$44.01	$39.52	0.3825	$41.48	$37.46	0.30
Fourth	$43.00	$39.83	0.3825	$38.93	$36.01	0.30
Annual	$45.00	$37.03	$1.4450	$41.48	$33.62	$1.20

ISSUER PURCHASES OF EQUITY SECURITIES

2013	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (a)	Maximum Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (Millions of Dollars)
October 1 - October 31	74,455	$40.27	74,455	$42.3
November 1 - November 30	482,156	$41.56	482,156	$22.2
December 1 - December 31	—	$—	—	$—
Total	556,611	$41.38	556,611	

(a) On May 5, 2011, Wisconsin Energy's Board of Directors authorized a share repurchase program for up to $300 million of our common stock which expired on December 31, 2013. We repurchased an aggregate of $277.8 million of our common stock under this program. On December 5, 2013, our Board of Directors authorized a new share repurchase program for up to $300 million of our common stock effective January 1, 2014 through December 31, 2017.

ITEM 6. SELECTED FINANCIAL DATA

WISCONSIN ENERGY CORPORATION

CONSOLIDATED SELECTED FINANCIAL AND STATISTICAL DATA

Financial	2013	2012	2011	2010	2009
Year Ended December 31					
Net income - Continuing Operations (Millions)	$577.4	$546.3	$512.8	$454.4	$375.7
Earnings per share - Continuing Operations					
Basic	$2.54	$2.37	$2.20	$1.94	$1.61
Diluted	$2.51	$2.35	$2.18	$1.92	$1.59
Dividends per share of common stock	$1.445	$1.20	$1.04	$0.80	$0.675
Operating revenues (Millions)					
Utility energy	$4,462.0	$4,190.8	$4,431.5	$4,165.3	$4,092.0
Non-utility energy	446.7	439.9	435.1	320.2	163.1
Eliminations and Other	(389.7)	(384.3)	(380.2)	(283.0)	(154.2)
Total operating revenues	$4,519.0	$4,246.4	$4,486.4	$4,202.5	$4,100.9
As of December 31 (Millions)					
Total assets	$14,769.4	$14,285.0	$13,862.1	$13,059.8	$12,697.9
Long-term debt (including current maturities) and capital lease obligations	$4,705.4	$4,865.9	$4,646.9	$4,405.4	$4,171.5
Common Stock Closing Price	$41.34	$36.85	$34.96	$29.43	$24.92

CONSOLIDATED SELECTED QUARTERLY FINANCIAL DATA

	(Millions of Dollars, Except Per Share Amounts) (a)			
	March		June	
Three Months Ended	2013	2012	2013	2012
Operating revenues	$1,275.2	$1,191.2	$1,012.3	$944.7
Operating income	$321.0	$295.7	$229.5	$222.6
Total net income	$176.6	$172.1	$119.0	$119.3
Earnings per share of common stock (b)				
Basic	$0.77	$0.75	$0.52	$0.52
Diluted	$0.76	$0.74	$0.52	$0.51
	September		December	
Three Months Ended	2013	2012	2013	2012
Operating revenues	$1,053.2	$1,039.3	$1,178.3	$1,071.2
Operating income	$258.0	$280.6	$271.6	$201.4
Total net income	$137.5	$156.1	$144.3	$98.8
Earnings per share of common stock (b)				
Basic	$0.61	$0.68	$0.64	$0.43
Diluted	$0.60	$0.67	$0.63	$0.43

(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, which primarily owns and leases to Wisconsin Electric electric power generating facilities constructed as part of 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 our electric and gas customers under the trade name of We Energies. We Energies operates under a traditional rate regulated cost of service environment. During 2013, our regulated utility earned $719.4 million of operating income. Over the next five years, we expect to invest between $3.1 billion and $3.3 billion in this business.

We have a 26.2% ownership interest in ATC, a MISO member company regulated by FERC. Our investment in ATC totaled $402.7 million as of December 31, 2013, and our 2013 pre-tax earnings from ATC totaled $68.5 million. Over the next five years, in addition to any potential investment through our undistributed earnings in ATC, we expect to make capital contributions of approximately $130 million in ATC as it continues to invest in transmission projects.

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 leases. Our operating income from our non-utility business totaled $367.1 million during 2013, and we expect comparable earnings from this segment in 2014. The PTF strategy was developed with the primary goal of constructing these power plants. Over the next five years, we do, however, expect to invest approximately $117 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 2013, 2012 and 2011:

Wisconsin Energy Corporation	2013	2012	2011
	(Millions of Dollars)		
Utility Energy	$719.4	$647.7	$544.8
Non-Utility Energy	367.1	358.8	348.9
Corporate and Other	(6.4)	(6.2)	(6.4)
Total Operating Income	1,080.1	1,000.3	887.3
Equity in Earnings of Transmission Affiliate	68.5	65.7	62.5
Other Income and Deductions, net	18.8	34.8	62.7
Interest Expense, net	252.1	248.2	235.8
Income from Continuing Operations Before Income Taxes	915.3	852.6	776.7
Income Tax Expense	337.9	306.3	263.9
Income from Continuing Operations	577.4	546.3	512.8
Income from Discontinued Operations, Net of Tax	—	—	13.4
Net Income	$577.4	$546.3	$526.2
Diluted Earnings Per Share			
Continuing Operations	$2.51	$2.35	$2.18
Discontinued Operations	—	—	0.06
Total Diluted Earnings Per Share	$2.51	$2.35	$2.24

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 2013, 2012 and 2011:

Utility Energy Segment	2013	2012	2011
	(Millions of Dollars)		
Operating Revenues			
Electric	$3,308.7	$3,193.9	$3,211.3
Gas	1,113.7	962.6	1,181.2
Other	39.6	34.3	39.0
Total Operating Revenues	4,462.0	4,190.8	4,431.5
Operating Expenses			
Fuel and Purchased Power	1,158.1	1,103.8	1,174.5
Cost of Gas Sold	674.1	545.8	728.7
Other Operation and Maintenance	1,522.0	1,476.5	1,613.4

Depreciation and Amortization	320.2	296.4	257.0
Property and Revenue Taxes	116.2	120.6	113.1
Total Operating Expenses	3,790.6	3,543.1	3,886.7
Treasury Grant	48.0	—	—
Operating Income	$719.4	$647.7	$544.8

2013 vs. 2012: Our utility energy segment contributed $719.4 million of operating income during 2013 compared with $647.7 million of operating income during 2012. The increase in operating income was primarily caused by favorable winter weather during 2013 and pricing increases, partially offset by an increase in operation and maintenance expense and depreciation.

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.

Electric Utility Gross Margin

The following table compares our electric utility gross margin during 2013 with similar information for 2012 and 2011, including a summary of electric operating revenues and electric sales by customer class:

	Electric Revenues and Gross Margin			MWh Sales		
Electric Utility Operations	2013	2012	2011	2013	2012	2011
	(Millions of Dollars)			(Thousands)		
Customer Class						
Residential	$1,208.6	$1,163.9	$1,159.2	8,141.9	8,317.7	8,278.5
Small Commercial/Industrial	1,048.0	1,013.6	1,006.9	8,860.4	8,860.0	8,795.8
Large Commercial/Industrial	711.9	744.3	763.7	8,673.4	9,710.7	9,992.2
Other - Retail	23.4	22.8	22.9	152.3	154.8	153.6
Total Retail	2,991.9	2,944.6	2,952.7	25,828.0	27,043.2	27,220.1
Wholesale - Other	143.7	144.4	154.0	1,953.5	1,566.6	2,024.8
Resale - Utilities	143.2	53.4	69.5	4,382.7	1,642.4	2,065.7
Other Operating Revenues	28.4	51.5	35.1	—	—	—
Total	3,307.2	3,193.9	3,211.3	32,164.2	30,252.2	31,310.6
Electric Customer Choice (a)	1.5	—	—	813.0	—	—
Total, including electric customer choice	3,308.7	3,193.9	3,211.3			
Fuel and Purchased Power						
Fuel	611.1	541.6	644.4			
Purchased Power	533.4	548.7	514.8			
Total Fuel and Purchased Power	1,144.5	1,090.3	1,159.2			
Total Electric Gross Margin	$2,164.2	$2,103.6	$2,052.1			
Weather - Degree Days (b)						
Heating (6,580 Normal)				7,233	5,704	6,633
Cooling (730 Normal)				688	1,041	793

(a) Represents distribution sales for customers who have purchased power from an alternative electric supplier in Michigan.

(b) 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

2013 vs. 2012: Our electric utility operating revenues increased by $114.8 million, or 3.6%, when compared to 2012. The most significant factors that caused a change in revenues were:

- Wisconsin net retail pricing increases of $115.6 million ($177.7 million less $62.1 million related to Section 1603 Renewable Energy Treasury Grant (Treasury Grant) bill credits), which is primarily related to our 2013 Wisconsin Rate Case. For information on the Treasury Grant and the rate order in the 2013 rate case, see

Factors Affecting Results, Liquidity and Capital Resources -- Accounting Developments and -- Utility Rates and Regulatory Matters, respectively.

- A $89.8 million increase in sales for resale due to increased sales into the MISO Energy Markets as a result of increased availability of our generating units.
- A $48.0 million decrease in large commercial/industrial sales due to the two iron ore mines that switched to an alternative electric supplier effective September 1, 2013. See Factors Affecting Results, Liquidity and Capital Resources -- Industry Restructuring and Competition -- Restructuring in Michigan, for a discussion of the impact of industry restructuring in Michigan on our electric sales.
- A $23.1 million decrease in other operating revenues, primarily driven by the amortization of $25.9 million in 2012 related to the settlement with the United States Department of Energy (DOE). For additional information on the DOE settlement, see Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters -- 2012 Fuel Cost Plan Request.
- A return to more normal summer weather as compared to the prior year that decreased electric revenues by an estimated $17.7 million.

As measured by cooling degree days, 2013 was 5.8% cooler than normal, and 33.9% cooler than 2012. Residential sales decreased by 2.1%, primarily due to the weather. Sales to our large commercial/industrial customers decreased by 10.7% primarily because of a decrease in sales to the two iron ore mines in Michigan. If the mines are excluded, sales to our large commercial/industrial customers decreased 3.0%. The two iron ore mines, which we served on an interruptible tariff rate, switched to an alternative electric supplier effective September 1, 2013. In addition, other smaller retail customers have switched to an alternative electric supplier. Wholesale - Other sales increased 24.7% primarily due to increased off-peak energy sales which generate lower incremental revenue because the majority of our wholesale revenue is tied to demand.

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 2011 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 the settlement with the DOE.
- A planned outage at an iron ore mine in 2012 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 one of the iron ore mines in Michigan 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.

Electric Fuel and Purchased Power Expenses

2013 vs. 2012: Our electric fuel and purchased power costs increased by $54.2 million, or approximately 5.0%, when compared to 2012. This increase was primarily caused by a 6.3% increase in total MWh sales, partially offset by a decrease in our average cost of fuel because of outage timing and a decrease in coal costs.

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.

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 2013, 2012 and 2011.

Gas Utility Operations	2013	2012	2011
	(Millions of Dollars)		
Operating Revenues	$1,113.7	$962.6	$1,181.2
Cost of Gas Sold	674.1	545.8	728.7
Gross Margin	$439.6	$416.8	$452.5

We believe gross margin is a better performance indicator than revenues because changes in the cost of gas sold flow through to revenue under GCRMs. The following table compares our gas utility gross margin and therm deliveries by customer class during 2013, 2012 and 2011:

	Gross Margin			Therm Deliveries		
Gas Utility Operations	2013	2012	2011	2013	2012	2011
	(Millions of Dollars)			(Millions)		
Customer Class						
Residential	$284.2	$267.9	$290.2	872.0	676.4	776.8
Commercial/Industrial	96.5	88.8	101.5	499.9	390.6	461.7
Interruptible	1.8	1.7	1.8	18.1	14.6	16.0
Total Retail	382.5	358.4	393.5	1,390.0	1,081.6	1,254.5
Transported Gas	51.7	52.9	52.6	1,052.8	1,140.4	899.6
Other Operating	5.4	5.5	6.4	—	—	—
Total	$439.6	$416.8	$452.5	2,442.8	2,222.0	2,154.1
Weather - Degree Days (a)						
Heating (6,580 Normal)				7,233	5,704	6,633

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

2013 vs. 2012: Our total retail gas margin increased by $24.1 million, or approximately 6.7%, when compared to 2012. We estimate that colder winter weather increased gas margins by approximately $56.9 million. As measured by heating degree days, 2013 was 26.8% colder than 2012 and 9.9% colder than normal. Gas margins were reduced by $42.3 million because of lower gas rates that became effective January 1, 2013.

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.

Other Operation and Maintenance Expense

2013 vs. 2012: Our other operation and maintenance expense increased by $45.5 million, or approximately 3.1%, when compared to 2012. This increase was primarily driven by the reinstatement of $148.0 million of regulatory amortizations, offset in part by a $50.1 million reduction in bad debt expense related to our natural gas customers and continued cost control efforts across our utilities. For additional information on the regulatory amortizations, see Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters -- 2012 Wisconsin Rate Case.

Our utility operation and maintenance expenses are influenced by, among other things, labor costs, employee benefit costs, plant outages and amortization of regulatory assets.

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 $148.0 million of amortization expense on certain regulatory assets as authorized under our 2012 Wisconsin Rate Case.

Depreciation and Amortization Expense

2013 vs. 2012: Depreciation and Amortization expense increased by $23.8 million, or approximately 8.0%, when compared to 2012. This increase was primarily because of an overall increase in utility plant in service. The emission control equipment for units 5 and 6 of the Oak Creek Air Quality Control System (AQCS) project went into service in March 2012, and for units 7 and 8 in September 2012. In addition, our new biomass plant went into service in November 2013. For additional information on the AQCS and biomass facility, see Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters -- Oak Creek Air Quality Control System and -- Renewables, Efficiency, and Conservation, respectively.

We expect depreciation and amortization expense to increase in 2014 primarily as a result of an increase in utility plant in service related to the biomass plant, which will have been in service a full year.

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.

Treasury Grant

During 2013, we recognized $48 million of income related to a Treasury Grant associated with our recently completed biomass plant. The grant income that we recognized in income is equal to the bill credits provided to our retail electric customers in Wisconsin before related tax benefits. For additional information on the Treasury Grant, see Factors Affecting Results, Liquidity and Capital Resources -- Accounting Developments.

During 2014, we expect to recognize approximately $13 million of grant income. This amount is equal to the bill credits we expect to provide to our retail electric customers in Wisconsin before related tax benefits.

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).

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.

	2013	2012	2011
	(Millions of Dollars)		
Operating Revenues	$446.7	$439.9	$435.1
Operation and Maintenance Expense	12.5	14.0	13.7
Depreciation Expense	67.1	67.1	72.5
Operating Income	$367.1	$358.8	$348.9

2013 vs. 2012: Non-utility energy segment operating income increased $8.3 million, or approximately 2.3%, when compared to 2012. The increase primarily relates to the increase in operating revenues related to the final approved construction costs for the Oak Creek expansion as part of the 2013 Wisconsin Rate Case.

In 2014, we expect our non-utility energy segment operating revenue to stay relatively flat compared to 2013.

2012 vs. 2011: Non-utility energy segment operating income increased $9.9 million, or approximately 2.8%, when compared to 2011. This increase primarily relates to 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 compared to eleven and a half months of earnings for 2011.

CORPORATE AND OTHER CONTRIBUTION TO OPERATING INCOME

2013 vs. 2012: Corporate and other affiliates had an operating loss of $6.4 million in 2013 compared with an operating loss of $6.2 million in 2012.

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.

CONSOLIDATED OTHER INCOME AND DEDUCTIONS, NET

Other Income and Deductions, net	2013	2012	2011
	(Millions of Dollars)		
AFUDC - Equity	$18.3	$35.3	$59.4
Other, net	0.5	(0.5)	3.3
Total Other Income and Deductions, net	$18.8	$34.8	$62.7

2013 vs. 2012: Other income and deductions, net decreased by approximately $16.0 million, or 46.0%, when compared to 2012. This decrease primarily relates to lower AFUDC - Equity related to 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, partially offset by the biomass plant which went into service in November 2013.

During 2014, we expect to see a reduction in AFUDC - Equity as we expect to have fewer large construction projects.

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 lower 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.

CONSOLIDATED INTEREST EXPENSE, NET

Interest Expense, net	2013	2012	2011
	(Millions of Dollars)		
Gross Interest Costs	$261.5	$264.1	$262.5
Less: Capitalized Interest	9.4	15.9	26.7
Interest Expense, net	$252.1	$248.2	$235.8

2013 vs. 2012: Our net interest expense increased by $3.9 million, or 1.6%, as compared to 2012 primarily because of lower capitalized interest. Our capitalized interest decreased by $6.5 million primarily because of lower construction work in progress.

During 2014, we expect to see slightly lower net interest expense as gross interest costs are expected to decrease due to a lower weighted average embedded interest rate on our long-term debt. We expect this decrease will be partially offset by a reduction in capitalized interest as a result of the biomass plant going into service in 2013.

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.

CONSOLIDATED INCOME TAX EXPENSE

2013 vs. 2012: Our effective tax rate applicable to continuing operations was 36.9% in 2013 compared to 35.9% in 2012. This increase in our effective tax rate was due to reduced domestic production activities deductions and AFUDC - Equity. For further information, see Note G -- Income Taxes in the Notes to Consolidated Financial Statements. We expect our 2014 annual effective tax rate to be between 37.5% and 38.5%.

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.

LIQUIDITY AND CAPITAL RESOURCES

CASH FLOWS

The following table summarizes our cash flows during 2013, 2012 and 2011:

	2013	2012	2011
	(Millions of Dollars)		
Cash Provided by (Used in)			
Operating Activities	$1,231.0	$1,173.9	$993.4
Investing Activities	$(745.8)	$(729.6)	$(892.5)
Financing Activities	$(494.8)	$(422.8)	$(111.3)

Operating Activities

2013 vs. 2012: Cash provided by operating activities was $1,231.0 million during 2013, which was an increase of $57.1 million over 2012. The increase is primarily because of lower contributions to our qualified benefit plans and higher non-cash charges to earnings. During 2013, we made no contributions to our qualified benefit plans, compared to contributions of $100 million during 2012. In addition, we had higher net income, depreciation expense and amortization expense. Included in the higher amortization expense is a $77.9 million increase in the

amortization of regulatory items. Partially offsetting these items is an increase in accounts receivable and accrued revenues of $201.2 million because of colder winter weather and the Treasury Grant.

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.

Investing Activities

2013 vs. 2012: Cash used in investing activities was $745.8 million during 2013, which was $16.2 million higher than 2012. Our change in restricted cash decreased by $40.1 million, which is related to the 2012 release of restricted cash through bill credits and the reimbursement of costs associated with the DOE settlement. Our capital expenditures decreased by $19.6 million during 2013 as compared to 2012, primarily because of decreased spending as the Oak Creek AQCS project went into service in 2012.

The following table identifies capital expenditures by year:

Capital Expenditures	2013	2012	2011
	(Millions of Dollars)		
Utility	$657.9	$697.3	$792.2
We Power	26.1	5.5	31.2
Other	3.4	4.2	7.4
Total Capital Expenditures	$687.4	$707.0	$830.8

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.

Financing Activities

The following table summarizes our cash flows from financing activities:

	2013	2012	2011
	(Millions of Dollars)		
Dividends on Common Stock	$(328.9)	$(276.3)	$(242.0)
Common Stock Repurchased, Net	(174.9)	(103.4)	(139.5)
Net Increase (Decrease) in Debt	(3.4)	(43.8)	265.4

Other	12.4	0.7	4.8
Cash Used in Financing	$(494.8)	$(422.8)	$(111.3)

2013 vs. 2012: Cash used in financing activities was $494.8 million during 2013, compared to $422.8 million during 2012. Our dividends paid on common stock increased by $52.6 million during 2013 as compared to 2012, as a result of increases in the quarterly common stock dividend of 13.3% and 12.5% in the first and third quarter, respectively.

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. In 2013, we repurchased approximately 3.0 million shares in the open market pursuant to this program at a total cost of $126.0 million, compared to 1.5 million shares at a cost of $51.8 million in 2012.

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. In addition, our common stock dividends increased in 2012 as we raised our quarterly dividend rate by 15.4%.

No new shares of Wisconsin Energy's common stock were issued in 2013, 2012 or 2011. During these years, our independent plan agents purchased, in the open market, 2.4 million shares at a cost of $97.4 million, 2.8 million shares at a cost of $101.4 million and 3.0 million shares at a cost of $93.9 million, respectively, to fulfill exercised stock options and restricted stock awards. In 2013, 2012 and 2011, we received proceeds of $48.5 million, $49.8 million and $54.4 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

Liquidity

We anticipate meeting our capital requirements during 2014 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, 2013, we had approximately $1.2 billion of available, undrawn lines under our bank back-up credit facilities. As of December 31, 2013, we had approximately $537.4 million of commercial paper outstanding on a consolidated basis that was supported by the available lines of credit. During 2013, our maximum commercial paper outstanding was $594.5 million with a weighted-average interest rate of 0.25%. For additional information regarding our commercial paper balances during 2013, see Note K -- 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, 2013:

Company	Total Facility	Letters of Credit	Credit Available

	(Millions of Dollars)			Facility Expiration
Wisconsin Energy	$400.0	$0.1	$399.9	December 2017
Wisconsin Electric	$500.0	$6.1	$493.9	December 2017
Wisconsin Gas	$350.0	$—	$350.0	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, 2013 and 2012, 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	2013 Actual	2013 Adjusted	2012 Actual	2012 Adjusted
	(Millions of Dollars)			
Common Equity	$4,233.0	$4,483.0	$4,135.1	$4,385.1
Preferred Stock of Subsidiary	30.4	30.4	30.4	30.4
Long-Term Debt (including current maturities)	4,705.4	4,455.4	4,865.9	4,615.9
Short-Term Debt	537.4	537.4	394.6	394.6
Total Capitalization	$9,506.2	$9,506.2	$9,426.0	$9,426.0
Total Debt	$5,242.8	$4,992.8	$5,260.5	$5,010.5
Ratio of Debt to Total Capitalization	55.2 %	52.5 %	55.8 %	53.2 %

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 Sheets as of December 31, 2013 and 2012 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, 2013, the repurchased bonds were still outstanding, but were not reported as 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.

On December 5, 2013, the Board of Directors reviewed management's plan to maintain an appropriate capital structure by retiring up to $500 million of the holding company's obligations during the period 2014 through 2017.

Bonus Depreciation Provisions

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. These rules apply to the biomass plant we constructed in Rothschild, which went into service in November 2013. As a result of the increased federal tax

depreciation for 2013 and prior years, we did not make federal income tax payments for 2013 and do not anticipate making federal income tax payments for 2014.

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, 2013, we estimate that the collateral or the termination payments required under these agreements totaled approximately $214.6 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 January 2014, Moody's raised the ratings of Wisconsin Energy (senior unsecured to A2 from A3; junior subordinated to A3 from Baa1; commercial paper to P-1 from P-2), Wisconsin Electric (senior unsecured to A1 from A2), Wisconsin Gas (senior unsecured to A1 from A2), Elm Road Generating Station Supercritical, LLC (ERGSS) (senior notes to A1 from A2) and Wisconsin Energy Capital Corporation (WECC) (senior unsecured to A2 from A3). The commercial paper ratings of Wisconsin Electric and Wisconsin Gas remained at P-1. Moody's assigned a stable ratings outlook to each company.

In December 2013, S&P raised the ratings of Wisconsin Gas commercial paper to A-1 from A-2, and senior unsecured to A from A-. S&P also affirmed the stable rating outlook.

In June 2013, S&P affirmed the ratings of Wisconsin Energy (commercial paper, A-2; senior unsecured, BBB+; junior subordinated, BBB), Wisconsin Electric (commercial paper, A-2; senior unsecured, A-), Wisconsin Gas (commercial paper, A-2; senior unsecured, A-), WECC (senior unsecured, A-) and ERGSS (senior notes, A-). S&P also revised the ratings outlooks assigned to each company from positive to stable.

In June 2013, Fitch Ratings (Fitch) affirmed the ratings of Wisconsin Energy (commercial paper, F2; senior unsecured, A-; junior subordinated, BBB), Wisconsin Electric (commercial paper, F1; senior unsecured, A+), Wisconsin Gas (commercial paper, F1), WECC (senior unsecured, A-) and ERGSS (senior notes, A+). At the same time, Fitch lowered the senior unsecured rating of Wisconsin Gas to A from 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 capital expenditures for the next three years are as follows:

Capital Expenditures	2014	2015	2016

(Millions of Dollars)

Utility	$667.9	$777.6	$587.6
We Power	38.6	19.8	28.7
Other	4.5	6.8	5.5
Total	$711.0	$804.2	$621.8

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: On December 5, 2013, our Board of Directors authorized a new share repurchase program for up to $300 million of our common stock from January 1, 2014 through the end of 2017. Funds for the repurchases are expected 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 addition, on January 16, 2014, our Board of Directors increased our quarterly common stock dividend to $0.39 per share, up approximately 2.0%, from $0.3825 per share.

Investments in Outside Trusts: We use outside trusts to fund our pension and certain other post-retirement obligations. These trusts had investments of approximately $1.8 billion as of December 31, 2013. These trusts hold investments that are subject to the volatility of the stock market and interest rates.

During 2013, we made no contributions to our qualified pension plans or our qualified Other Post-Retirement Employee Benefit (OPEB) plans. During 2012, we contributed $95.6 million to our qualified pension plans and $4.4 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 N -- 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, 2013:

Contractual Obligations (a)	Payments Due by Period				
	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
	(Millions of Dollars)				
Long-Term Debt Obligations (b)	$8,709.7	$556.3	$917.8	$674.8	$6,560.8
Capital Lease Obligations (c)	215.9	41.9	88.6	28.6	56.8
Operating Lease Obligations (d)	40.5	3.9	7.6	6.3	22.7
Purchase Obligations (e)	12,189.3	892.3	1,309.4	1,067.9	8,919.7
Other Long-Term Liabilities	1,000.1	104.1	199.4	201.0	495.6
Total Contractual Obligations	$22,155.5	$1,598.5	$2,522.8	$1,978.6	$16,055.6

(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. This amount does not include We Power leases to Wisconsin Electric which are eliminated upon consolidation.

(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, 2013, our regulatory assets totaled $1,108.5 million and our regulatory liabilities totaled $879.1 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. The fuel rules 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 Proceedings.

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 2013, 2012 and 2011, 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, 2013. 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, 2013 of our outstanding portfolio of commercial paper and variable rate long-term debt. As of December 31, 2013, we had $537.4 million of commercial paper outstanding with a weighted average interest rate of 0.20% 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 $6.8 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, 2013 was approximately:

	Millions of Dollars
Pension trust funds	$1,451.0
Other post-retirement benefits trust funds	$327.6

The expected long-term rate of return on plan assets for 2014 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 Oak Creek expansion 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. The warranty claim for costs incurred to repair steam turbine corrosion damage identified on both units was scheduled to go to arbitration in October 2013, but we entered into a settlement agreement with Bechtel in June 2013 resolving the claim, as well as several other warranty claims. This settlement did not have a material impact to our financial statements. Bechtel and Wisconsin Electric continue to work through two remaining items.

Pursuant to the terms of this settlement agreement, Bechtel achieved final acceptance of both Oak Creek expansion units.

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, for the year ended December 31, 2013, we estimate that approximately 87% of our electric revenues were regulated by the PSCW, 4% were regulated by the MPSC and the balance of our electric revenues was regulated by FERC. Because of the loss of several Michigan customers to an alternative electric supplier, the percentage of revenues regulated by the MPSC is likely to decline in the future. 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/.

General Rate Proceedings

2013 Wisconsin Rate Case: In March 2012, Wisconsin Electric and Wisconsin Gas initiated rate proceedings with the PSCW. In December 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%) of bill credits related to the proceeds of the Treasury Grant, including related tax benefits. Absent this offset, the retail electric rate increase for non-fuel costs was approximately $133 million (4.8%) for 2013.
- An electric rate increase for Wisconsin Electric's Wisconsin electric customers of approximately $28 million (1.0%) for 2014, and a $45 million (1.6%) reduction in bill credits.
- Recovery of a forecasted increase in fuel costs of approximately $44 million (1.6%) for 2013.
- A rate decrease of approximately $8 million (1.9%) for Wisconsin Electric's natural gas customers for 2013, with no rate adjustment in 2014. The new Wisconsin Electric rates reflect a $6.4 million reduction in bad debt expense.
- A rate decrease of approximately $34 million (5.5%) for Wisconsin Gas' natural gas customers for 2013, with no rate adjustment in 2014. The new Wisconsin Gas rates reflect a $43.8 million reduction in bad debt expense.
- 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 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 Treasury Grant. In the first half of 2014, Wisconsin Electric and Wisconsin Gas expect to seek base rate increases to be effective in 2015.

2012 Wisconsin Rate Case: In May 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, among other things:

- 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.

We received a final written order from the PSCW in November 2011.

2012 Michigan Rate Case: In July 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. In 2014, Wisconsin Electric expects to seek a base rate increase to be effective in 2015.

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;
- 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. The PSCW issued a final decision, increasing annual Wisconsin retail rates by $25.4 million effective April 29, 2011. The net increase was 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 July 2010, the MPSC issued its final order, approving a total increase of $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.

Wisconsin Fuel Proceedings

Embedded within Wisconsin Electric's base electric rates is an amount to recover fuel costs. The Wisconsin retail fuel rules 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. The deferred fuel costs are subject to an excess revenues test.

2014 Fuel Cost Plan Request: On July 30, 2013, Wisconsin Electric filed its 2014 fuel cost plan with the PSCW requesting authority to decrease Wisconsin retail electric customers rates approximately $36 million in the form of a fuel credit primarily related to a reduction in delivered coal costs. The plan was approved by the PSCW on December 20, 2013.

2012 Fuel Cost Plan 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. 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.

In November 2000, Wisconsin Electric filed a complaint against the DOE in the Court of Federal Claims for DOE's failure to remove used nuclear fuel from Point Beach, which Wisconsin Electric owned until September 2007. 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.

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).

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 Wisconsin. 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, 2013, we had $126.8 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.

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, 2013, 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 constructed a 50 MW biomass facility at Domtar Corporation's

Rothschild, Wisconsin paper mill site that went into commercial operation on November 8, 2013. Wood waste and wood shavings are used to produce renewable electricity and will also support Domtar's sustainable papermaking operations. The final cost of completing this project was $269.0 million, excluding AFUDC. We also own four wind sites, consisting of 200 turbines with an installed capacity of 338 MW and a dependable capability of 66 MW.

We expect to be in compliance with Act 141's 2015 standard, and have entered into agreements for renewable energy credits which should allow us to remain in compliance with Act 141 through 2022. If market conditions are favorable, we may purchase more renewable energy credits.

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 2013. The funding required by Act 141 for 2014 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.

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 filed an application with the PSCW seeking approval to construct a new natural gas lateral on March 28, 2013. The anticipated cost of the initial phase of this project is approximately $150 million to $170 million, excluding AFUDC.

ELECTRIC SYSTEM RELIABILITY

We continue to upgrade our electric distribution system, including substations, transformers and lines. We had adequate capacity to meet the MISO calculated planning reserve margin during 2013 and 2012. 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 the planning reserve margin requirements during 2014. However, extremely hot weather, unexpected equipment failure or unavailability across the 15-state MISO market footprint 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 have continued to pursue a proactive strategy to manage our environmental compliance obligations, including: (1) the development of additional sources of renewable electric energy supply; (2) the review of water quality matters

such as discharge limits and cooling water requirements and implementing improvements to our cooling water intake systems as needed; (3) the addition of emission control equipment to existing facilities to comply with new ambient air quality standards and federal clean air rules; (4) the conversion of the fuel source for VAPP from coal to natural gas; (5) the beneficial use of ash and other solid products from coal-fired generating units; and (6) 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 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 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 do not expect future costs to have a material impact on our 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. In January 2014, environmental groups petitioned the U.S. District Court for the Northern District of California to order the EPA to propose a new ozone standard by the end of 2014 and to finalize the standard by October 2015. We expect that the EPA could lower the current 8-hour ozone standard from its current level.

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 SIP including reasonably available control technology (RACT) regulations. In December 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. Also in December 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. This standard represented a significant change from the previous SO_2 standard. The implementation guidance for the new standard, 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 advised that it is revisiting this implementation guidance. The EPA issued two technical assistance documents for comment in 2013, and expects to issue a rule in 2014 that will establish requirements for characterizing SO_2 air quality in priority areas.

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 standard remains in place, we do not believe that we will need to make any significant additional expenditures at the majority of our generating units because of prior investments in pollution control equipment. However, if the new standard does remain in place we believe that additional environmental controls will be required at PIPP located in the Upper Peninsula of Michigan.

In November of 2012, we entered into a joint venture agreement with Wolverine whereby Wolverine would pay for the installation of the air quality control systems at PIPP and receive a minority undivided ownership interest in the plant in return. However, in light of the loss of retail electric customers in Michigan due to that state's alternative electric supplier program (see Restructuring in Michigan under Industry Restructuring and Competition), we re-evaluated options related to the ownership and operation of PIPP including different alternatives for the joint venture with Wolverine. Ultimately, in December 2013, Wisconsin Electric and Wolverine decided to terminate the joint venture. We are currently evaluating options for the long-term future of PIPP, including the potential sale of the plant. At the same time, we are analyzing several environmental compliance options at PIPP.
The new standard 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. We currently anticipate that only PIPP will require modifications, and are currently evaluating several available options for PIPP to comply with MATS. In April 2013, we received a one year MATS compliance extension through April 16, 2016 from the MDEQ.
In January 2013, the EPA issued the National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters (Industrial Boiler MACT Rule). The Industrial Boiler MACT rule imposes stringent limitations on numerous hazardous air pollutants from large boilers that do not meet the definition of electric generating units. The compliance date set forth in the rule is January 31, 2016, but a one year extension of that deadline may be available where emission controls cannot be installed and operational by the compliance date. Along with some smaller gas fired boilers in our fleet, the boilers at the Milwaukee County Power Plant (MCPP) are subject to this rule. We are currently evaluating compliance options for the three coal fired boilers at MCPP.

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 plan. 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 technical revisions to the rule by the EPA, 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 successfully petitioned the United States Supreme Court, who heard the case in December 2013. A decision is expected by June 2014.

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 subsequent appeals, we will not be able to determine final regional haze requirements for NO_x and SO_2 at our facilities until the United States Supreme Court issues its decision and any subsequent rulemaking activities that may be required as a result of that decision 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:

- Repowered the Port Washington Power Plant from coal to natural gas-fired combined cycle units.
- Added coal-fired units as part of the Oak Creek expansion that are the most thermally efficient coal units in our system.
- Increased our investment in energy efficiency and conservation.
- Added renewable capacity.
- Planning to convert the fuel source at the VAPP from coal to natural gas.
- Retired coal units 1-4 at PIPP.

Federal, state, regional and international authorities have undertaken efforts to limit greenhouse gas emissions. The regulation of greenhouse gas emissions continues to be a top priority for the President's administration. In June 2013, the President issued a presidential memorandum instructing the EPA to, among other things, issue rules pertaining to greenhouse gas emissions from both new and existing power plants.

The EPA is pursuing regulation of greenhouse gas emissions using its existing authority under the CAA. On September 20, 2013, the EPA withdrew its 2012 proposed New Source Performance Standards greenhouse gas emissions rule, and issued new proposed rules with greenhouse gas limits for new fossil fueled power plants. The rule would not apply to certain natural gas fueled peaking plants, biomass units or oil fueled stationary combustion turbines. Based upon currently available technology and the emission limits in the proposed rule, we believe that this rule, if promulgated, would effectively prohibit new conventional coal-fired power plants.

With respect to existing generating units, the EPA has indicated that it intends to issue a proposed rule in June 2014, a final rule by June 2015 and require SIPs to be submitted by June 30, 2016. 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 2012, we reported CO_2 equivalent emissions of approximately 18.1 million metric tonnes to the EPA, compared with approximately 22.4 million metric tonnes for 2011. Based upon our preliminary analysis of the data, we estimate that we will report CO_2 equivalent emissions of approximately 21.9 million metric tonnes to the EPA for 2013. 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 2012, we reported approximately 8.4 million metric tonnes of CO_2 to the EPA related to our distribution and sale of natural gas, compared with approximately 9.5 million metric tonnes for 2011. Based upon our preliminary analysis of the

monitoring data, we estimate that we will report CO_2 emissions of approximately 10.2 million metric tonnes to the EPA for 2013.

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 $65 million and $70 million, excluding AFUDC, and anticipate that the conversion will be completed by the end of 2015 or early 2016. We filed for a Certificate of Authority from the PSCW on April 26, 2013, and received preliminary approval on January 30, 2014. We expect to receive a final written order by the end of the first quarter. The construction air permit for the gas conversion was issued by the WDNR on November 11, 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. Construction began on the Lincoln Arthur natural gas main in March 2013. For further information, see Note Q -- 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; however, the promulgation of the final rule was delayed and is expected to occur by April 2014. Once the rule is final, we expect that 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.

In December, 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 guidelines regulate waste water discharges from our power plant processes. In June 2013, the EPA issued a proposed rule for comment to modify these guidelines. We submitted comments primarily addressing potential effects to our wastewater treatment facilities and coal combustion residuals effluent management activities. The rules are expected to be finalized by May 2014. After promulgation of the final rules, the WDNR and MDEQ will need to modify state rules accordingly and then incorporate new

requirements into our facility permits. The rule compliance deadline is as soon as possible after July 1, 2017 with full compliance expected by July 1, 2022. We already meet many of the proposed requirements defined by the EPA, and as a result believe we will be well positioned to comply with the proposed guidelines. There are several available options outlined in the proposed rule. The amount of additional costs we may need to incur to comply with the new guidelines, if any, will depend on which option(s) the EPA selects to incorporate into the final guidelines. Until the rules are finalized, we are unable to determine the impact on our facilities.

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 that the EPA could take action on a final rule by the end 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 received a letter from the EPA in 2013 that allows us to continue ash recovery and reburn as a non-hazardous secondary material based on our processing of the materials prior to reburning as currently allowed under the Secondary Materials Rule.

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 Q -- 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 Q -- Commitments and Contingencies in the Notes to Consolidated Financial Statements.

LEGAL MATTERS

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 have made 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.

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.

Restructuring in Wisconsin: Electric utility revenues in Wisconsin are regulated by the PSCW. 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: Under Michigan law, our retail customers may choose an alternative electric supplier to provide power supply service. The law limits customer choice to 10% of our Michigan retail load. The two iron ore mines are excluded from this cap. When a customer switches to an alternative electric supplier, we continue to provide distribution and customer service functions for the customer.

The mines, which we served on an interruptible tariff rate, switched to an alternative electric supplier effective September 1, 2013. In addition, other smaller retail customers have switched to an alternative electric supplier. Sales to these customers, including the mines, totaled 2,173.6 GWh, or 7.6% of our retail electric sales for the year ended December 31, 2012. Previously, the owner of the mines announced that they would shut down the Empire mine by the end of 2014 or beginning of 2015.

We have taken, and will continue to take, multiple steps to mitigate these impacts in 2014 and going forward. In August 2013, we filed a request with MISO to suspend the operation of all five units at PIPP. In October 2013, MISO informed us that the operation of all units is necessary to maintain reliability in the Upper Peninsula of Michigan. On January 30, 2014, we entered into a SSR Agreement with MISO to recover costs for operating and maintaining the units. The Agreement is effective February 1, 2014, has a one year term, and specifies monthly payments to Wisconsin Electric of $4.4 million to cover fixed costs. The Agreement also provides for the payment of our variable costs to operate and maintain the plant. MISO filed the SSR Agreement at FERC on January 31, 2014 and is requesting FERC's approval of this Agreement.

In addition, Wisconsin Electric filed an application with the MPSC requesting authority to defer all fixed production costs that would have been recovered from the customers who switched to an alternative electric supplier. In August 2013, the MPSC issued an order approving the deferral of costs allocable to our remaining Michigan retail customers. In September 2013, we filed a petition for re-hearing with the MPSC requesting reconsideration of its deferral order; however, our request was denied. Our ability to collect the deferred costs will be determined in a subsequent rate proceeding.

Wisconsin Electric files bi-annual retail rate cases in Wisconsin. Our next electric rate case in Wisconsin is for rates to be implemented in January 2015. Wholesale electric rates are set under FERC formula cost-based rates and are adjusted annually. We believe that prudently incurred utility costs will be recovered in future Wisconsin retail rate cases and FERC filings.

We do not expect the loss of these customers to have a material impact on our consolidated results of operations in 2014. Although the financial impact in future periods is uncertain, we expect that successful mitigation efforts and a reasonable regulatory response should make our net financial exposure immaterial.

Electric Transmission, Capacity 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, 2013 through May 31, 2014. The resulting ARR valuation and the secured FTRs are expected to mitigate our transmission congestion risk for that period.

Beginning June 1, 2013, MISO instituted an annual zonal resource adequacy requirement to ensure there is sufficient generation capacity to serve the MISO market. To meet this requirement, capacity resources could be acquired through MISO's annual capacity auction, bilateral contracts for capacity, or provided from generating or demand response resources. Our capacity requirements were fulfilled using our own capacity resources.

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 received a new air construction permit from the WDNR to modify the Oak Creek expansion units for potential future use of sub-bituminous coal. In May 2013, we began testing various combinations of sub-bituminous coal and bituminous coal to identify any equipment limitations that should be considered prior to filing with the PSCW for a Certificate of Authority to make any fuel flexibility modifications. In February 2013, the Sierra Club and the Midwest Environmental Defense Center filed a petition for a contested case hearing with the WDNR to challenge the issuance of the air construction permit. The WDNR has granted that petition, but a hearing has not yet been scheduled.

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) 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 Units 1 and 4 to remain out of service until at least the end of the second quarter of 2014. In December 2013, Act 91 was signed into law in Wisconsin, creating a process by which the EPA and WDNR may revise the regulations applicable to Units 1 and 4 and allow those units to restart.

In February 2013, the Sierra Club filed for a contested case hearing with the WDNR in connection with the administrative order. The WDNR has granted that petition, but a hearing has not yet been scheduled. In addition, in May 2013, the WDNR referred the matter to the Wisconsin Department of Justice for alleged violations of air management statutes and rules. We could be subject to fines and penalties.

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.

Treasury Grant: In December 2013, we filed an application with the United States Treasury for a Section 1603 renewable energy grant related to the construction of our biomass facility in Rothschild, Wisconsin. We recorded a receivable for $82.6 million related to the grant that we expect to receive in the first half of 2014. The PSCW anticipated the recognition of this grant as income when it set rates for the two years beginning January 1, 2013. During 2013, we have provided bill credits to our Wisconsin electric customers which reflects the grant as income. The bill credits also reflect the tax benefits related to the grant. The bill credits will continue in 2014.

During 2013, we recognized the Treasury Grant as income, less the amounts that we have established as a deferred liability. The amount reflected in earnings matched the amount of the bill credits given to customers. The deferred balance reflects the amount of the grant income that we expect to benefit our customers in the future. This accounting reflects the regulatory treatment of the grant.

The PSCW approved escrow accounting treatment for the Treasury Grant. Under escrow accounting, we true-up any differences between the actual grant proceeds received and the grant proceeds passed on to customers in the form of bill credits.

Tangible Property Regulations: During September 2013, the Treasury Department and IRS issued final regulations pertaining to costs incurred to acquire, maintain or improve tangible property. These regulations are generally effective for tax years beginning on or after January 1, 2014. We continue to evaluate what impact, if any, the adoption of the regulations will have on our consolidated financial statements; however, we do not currently expect the impact to be material.

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, 2013, we had $1,108.5 million in regulatory assets and $879.1 million in regulatory liabilities. In the future, if we move to market based rates, or if the actions of our regulators change, we may conclude that we are unable to follow 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 N -- 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	$5.2
0.5% decrease in expected rate of return on plan assets	$6.6

In addition to pension plans, we maintain OPEB plans which provide health and life insurance benefits for retired employees (described in Note N -- 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	$0.7
0.5% decrease in health care cost trend rate in all future years	$(1.5)
0.5% decrease in expected rate of return on plan assets	$1.4

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 2013 of approximately $4.5 billion included accrued utility revenues of $321.1 million as of December 31, 2013.

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 L -- Derivative Instruments and Note M -- 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

	2013	2012	2011
	(Millions of Dollars, Except Per Share Amounts)		
Operating Revenues	$4,519.0	$4,246.4	$4,486.4
Operating Expenses			
Fuel and purchased power	1,153.0	1,098.6	1,169.7
Cost of gas sold	674.1	545.8	728.7
Other operation and maintenance	1,155.0	1,116.1	1,256.8
Depreciation and amortization	388.1	364.2	330.2
Property and revenue taxes	116.7	121.4	113.7
Total Operating Expenses	3,486.9	3,246.1	3,599.1
Treasury Grant	48.0	—	—
Operating Income	1,080.1	1,000.3	887.3
Equity in Earnings of Transmission Affiliate	68.5	65.7	62.5
Other Income and Deductions, net	18.8	34.8	62.7
Interest Expense, net	252.1	248.2	235.8
Income from Continuing Operations Before Income Taxes	915.3	852.6	776.7
Income Tax Expense	337.9	306.3	263.9
Income from Continuing Operations	577.4	546.3	512.8
Income from Discontinued Operations, Net of Tax	—	—	13.4
Net Income	$577.4	$546.3	$526.2
Earnings Per Share (Basic)			
Continuing Operations	$2.54	$2.37	$2.20
Discontinued Operations	—	—	0.06
Total Earnings Per Share (Basic)	$2.54	$2.37	$2.26
Earnings Per Share (Diluted)			
Continuing Operations	$2.51	$2.35	$2.18
Discontinued Operations	—	—	0.06
Total Earnings Per Share (Diluted)	$2.51	$2.35	$2.24
Weighted Average Common Shares Outstanding (Millions)			

Basic	227.6	230.2	232.6
Diluted	229.7	232.8	235.4

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

WISCONSIN ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS
December 31

ASSETS

	2013	2012
	(Millions of Dollars)	
Property, Plant and Equipment		
In service	$14,966.3	$14,238.8
Accumulated depreciation	(4,257.1)	(4,036.0)
	10,709.2	10,202.8
Construction work in progress	149.6	315.9
Leased facilities, net	47.8	53.5
Net Property, Plant and Equipment	10,906.6	10,572.2
Investments		
Equity investment in transmission affiliate	402.7	378.3
Other	36.1	35.5
Total Investments	438.8	413.8
Current Assets		
Cash and cash equivalents	26.0	35.6
Accounts receivable, net of allowance for doubtful accounts of $61.0 and $58.0	406.0	285.3
Accrued revenues	321.1	278.1
Materials, supplies and inventories	329.4	360.7
Current deferred tax asset, net	310.0	105.3
Prepayments	145.7	145.5
Other	12.9	62.1
Total Current Assets	1,551.1	1,272.6
Deferred Charges and Other Assets		
Regulatory assets	1,108.5	1,380.3
Goodwill	441.9	441.9
Other	322.5	204.2
Total Deferred Charges and Other Assets	1,872.9	2,026.4
Total Assets	$14,769.4	$14,285.0

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

	2013	2012
	(Millions of Dollars)	
Capitalization		
Common equity	$4,233.0	$4,135.1
Preferred stock of subsidiary	30.4	30.4
Long-term debt	4,363.2	4,453.8
Total Capitalization	8,626.6	8,619.3
Current Liabilities		
Long-term debt due currently	342.2	412.1
Short-term debt	537.4	394.6
Accounts payable	342.6	368.4
Accrued payroll and benefits	96.9	100.9
Other	177.3	165.4
Total Current Liabilities	1,496.4	1,441.4
Deferred Credits and Other Liabilities		
Regulatory liabilities	879.1	868.4
Deferred income taxes - long-term	2,634.0	2,117.0
Deferred revenue, net	664.2	709.7
Pension and other benefit obligations	173.2	244.0
Other long-term liabilities	295.9	285.2
Total Deferred Credits and Other Liabilities	4,646.4	4,224.3
Commitments and Contingencies (Note Q)		
Total Capitalization and Liabilities	$14,769.4	$14,285.0

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

	2013	2012	2011
	(Millions of Dollars)		
Operating Activities			
Net income	$577.4	$546.3	$526.2
Reconciliation to cash			
Depreciation and amortization	400.2	371.7	336.4
Deferred income taxes and investment tax credits, net	312.7	293.2	430.6
Contributions to qualified benefit plans	—	(100.0)	(277.4)
Change in - Accounts receivable and accrued revenues	(162.9)	38.3	30.1
Inventories	31.3	21.3	(2.9)
Other current assets	2.8	12.1	(20.5)
Accounts payable	(14.8)	43.8	11.8
Accrued income taxes, net	36.6	116.9	(87.4)
Deferred costs, net	(8.7)	9.2	25.9
Other current liabilities	7.2	(14.9)	44.1
Other, net	49.2	(164.0)	(23.5)
Cash Provided by Operating Activities	1,231.0	1,173.9	993.4
Investing Activities			
Capital expenditures	(687.4)	(707.0)	(830.8)
Investment in transmission affiliate	(10.5)	(15.7)	(6.6)
Proceeds from asset sales	2.5	8.7	41.5
Change in restricted cash	2.7	42.8	(37.2)
Cost of removal, net of salvage	(37.8)	(38.3)	(16.9)
Other, net	(15.3)	(20.1)	(42.5)
Cash Used in Investing Activities	(745.8)	(729.6)	(892.5)
Financing Activities			
Exercise of stock options	48.5	49.8	54.4
Purchase of common stock	(223.4)	(153.2)	(193.9)
Dividends paid on common stock	(328.9)	(276.3)	(242.0)
Issuance of long-term debt	251.0	251.8	720.0
Retirement of long-term debt	(397.2)	(20.3)	(466.6)
Change in short-term debt	142.8	(275.3)	12.0
Other, net	12.4	0.7	4.8
Cash Used in Financing Activities	(494.8)	(422.8)	(111.3)
Change in Cash and Cash Equivalents	(9.6)	21.5	(10.4)
Cash and Cash Equivalents at Beginning of Year	35.6	14.1	24.5
Cash and Cash Equivalents at End of Year	$26.0	$35.6	$14.1

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, 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
Net income			577.4	577.4
Common stock cash dividends of $1.445 per share			(328.9)	(328.9)
Exercise of stock options		48.5		48.5
Purchase of common stock		(223.4)		(223.4)
Tax benefit from share based compensation		18.1		18.1
Stock-based compensation and other		6.2		6.2
Balance - December 31, 2013	$2.3	$349.7	$3,881.0	$4,233.0

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

WISCONSIN ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CAPITALIZATION
December 31

		2013	2012
		(Millions of Dollars)	
Common Equity (see accompanying statement)		$4,233.0	$4,135.1
Preferred Stock of Subsidiary (Note I)		30.4	30.4
Long-Term Debt			
Wisconsin Energy Notes (unsecured)	6.20% due 2033	200.0	200.0
	6.25% Junior Notes due 2067	500.0	500.0
Wisconsin Electric Debentures (unsecured)	4.50% due 2013	—	300.0
	6.00% due 2014	300.0	300.0
	6.25% due 2015	250.0	250.0
	1.70% due 2018	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
	5.70% due 2036	300.0	300.0
	3.65% due 2042	250.0	250.0
	6-7/8% due 2095	100.0	100.0
Wisconsin Electric Notes (unsecured)	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	(147.0)	(147.0)
Wisconsin Gas Debentures (unsecured)	6.60% due 2013	—	45.0
	5.20% due 2015	125.0	125.0
	5.90% due 2035	90.0	90.0
We Power Subsidiary Notes (secured, nonrecourse)	4.91% due 2013-2030 (b)	122.1	126.7
	5.209% due 2013-2030 (c)	231.5	238.6
	4.673% due 2013-2031 (c)	190.9	196.7
	6.00% due 2013-2033 (b)	138.4	142.1
	6.09% due 2030-2040 (c)	275.0	275.0
	5.848% due 2031-2041 (c)	215.0	215.0
WECC Notes (unsecured)	6.51% due 2013	—	30.0
	6.94% due 2028	50.0	50.0
Other Notes (secured, nonrecourse)	6.00% due 2021	1.8	1.8
	4.81% effective rate due 2030	2.0	2.0

Obligations under capital leases	104.3	120.0
Unamortized discount, net and other	(25.6)	(27.0)
Long-term debt due currently	(342.2)	(412.1)
Total Long-Term Debt	4,363.2	4,453.8
Total Capitalization	$8,626.6	$8,619.3

(a) Variable interest rate as of December 31, 2013.
(b) Senior notes are secured by a collateral assignment of the leases between PWGS and Wisconsin Electric related to PWGS 1 and 2.
(c) Senior notes are secured by a collateral assignment of the leases between ERGSS and Wisconsin Electric related to OC 1 and 2.

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 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 and Adjustments: As of December 31, 2013, we have presented the tax effect of net operating loss carryforwards within current deferred tax assets, net on the consolidated balance sheets. As of December 31, 2012, $59.0 million representing the tax effect of net operating loss carryforwards were included in income taxes receivable, which is a line item that has now been condensed within other current assets on the consolidated balance sheets. This $59.0 million amount has been adjusted in the consolidated balance sheets as of December 31, 2012 to conform to the December 31, 2013 presentation, and conforming changes have been made in the consolidated statements of cash flows and in the notes to the consolidated financial statements. For additional information related to our deferred tax assets, see Note G.

In addition, we have adjusted the presentation of regulatory assets and liabilities to present amounts as noncurrent assets and liabilities on the consolidated balance sheets. Prior period amounts recorded within other current assets and liabilities have been reclassified to conform to the current presentation. For additional information related to regulatory assets and liabilities, see Note C.

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

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

We recognize We Power 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.

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	2013	2012	2011
	(Millions of Dollars)		
AFUDC - Equity	$18.3	$35.3	$59.4
Other, net	0.5	(0.5)	3.3
Total Other Income and Deductions, net	$18.8	$34.8	$62.7

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

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

Property In Service	2013	2012
	(Millions of Dollars)	
Utility Energy	$11,779.8	$11,080.9
Non-Utility Energy	3,091.3	3,068.5
Other	95.2	89.4
Total	$14,966.3	$14,238.8

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 2013 and 2012, and 2.8% in 2011.

We depreciate our We Power assets 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 $724.5 million as of December 31, 2013 and $725.0 million as of December 31, 2012.

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

CWIP	2013	2012
	(Millions of Dollars)	
Utility Energy	$132.7	$298.2
Non-Utility Energy	16.5	13.3

Other	0.4	4.4
Total	$149.6	$315.9

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 utility segment recorded the following AFUDC for the years ended December 31:

	2013	2012	2011
	(Millions of Dollars)		
AFUDC - Debt	$7.7	$14.7	$24.7
AFUDC - Equity	$18.3	$35.3	$59.4

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 2013, 2012 and 2011 were included in the computation of diluted earnings per share. Anti-dilutive shares are excluded from the calculation.

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

Materials, Supplies and Inventories	2013	2012
	(Millions of Dollars)	
Fossil Fuel	$117.7	$165.5
Materials and Supplies	133.9	121.9
Natural Gas in Storage	77.8	73.3
Total	$329.4	$360.7

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. 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 L.

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

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, 2013 and 2012, 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 2013 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, 2013, 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, 2013 and 2012. 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 P.

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:

	2013	2012	2011
Risk-free interest rate	0.1% - 1.9%	0.1% - 2.0%	0.2% - 3.4%
Dividend yield	3.7%	3.9%	3.9%
Expected volatility	18.0%	19.0%	19.0%
Expected life (years)	5.9	5.9	5.5
Expected forfeiture rate	2.0%	2.0%	2.0%
Weighted-average fair value of our stock options granted	$3.45	$3.34	$3.17

Treasury Grant: In December 2013, we filed an application with the United States Treasury for a Section 1603 renewable energy grant related to the construction of our biomass facility in Rothschild, Wisconsin. The PSCW anticipated the recognition of this grant as income when it set rates for the two years beginning January 1, 2013. We provided bill credits to our customers in 2013, and this will continue into 2014. As of December 31, 2013, $48.0 million was recognized as income, which reflects the amount that was returned to customers in the form of bill credits during the year. We recorded an $82.6 million receivable, and deferred the balance that we expect to benefit our customers in the future. The accounting reflects the regulatory treatment of the grant.

The PSCW approved escrow accounting treatment for the Treasury Grant. Under escrow accounting, we true-up any differences between the actual grant proceeds received and the grant proceeds passed on to customers in the form of bill credits.

B -- RECENT ACCOUNTING PRONOUNCEMENTS

Offsetting Assets and Liabilities: In January 2013, the Financial Accounting Standards Board issued Accounting Standards Update (ASU) 2013-01, Disclosures about Offsetting Assets and Liabilities. The guidance requires enhanced disclosures about derivatives. Both gross and net information related to eligible transactions is 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. We adopted this guidance on January 1, 2013, and applied it retrospectively. The adoption and retrospective application of this guidance did not have any material impact on our financial statements. See Note L -- Derivative Instruments for the enhanced disclosures.

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, 2013, we had $10.1 million of regulatory assets not earning a return and $82.7 million of regulatory assets earning a return based on short-term interest rates.

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:

	2013	2012
	(Millions of Dollars)	
Regulatory Assets		
Deferred unrecognized pension costs	$537.6	$731.5
Deferred income tax related	169.5	176.5
Escrowed electric transmission costs	126.8	114.1
Escrowed conservation	66.9	73.5
Deferred plant related -- capital lease	56.5	66.6
Deferred environmental costs	47.0	47.4
Other, net	104.2	170.7
Total regulatory assets	$1,108.5	$1,380.3
Regulatory Liabilities		
Deferred cost of removal obligations	$724.5	$725.0
Escrowed bad debt costs	64.6	81.1
Other, net	90.0	62.2
Total regulatory liabilities	$879.1	$868.3

D -- ASSET SALES, DIVESTITURES AND DISCONTINUED OPERATIONS

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

	2013	2012	2011
	(Millions of Dollars)		
Income from Continuing Operations	$577.4	$546.3	$512.8
Income from Discontinued other operations, net of tax (a)	—	—	13.4
Net Income	$577.4	$546.3	$526.2

(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

AROs have been recorded for asbestos abatement at certain generation and substation facilities, and for obligations associated with the removal and dismantlement of generation facilities. AROs are recorded in other long-term liabilities on the Consolidated Balance Sheets. The following table presents the change in our AROs during 2013 and 2012:

	2013	2012
	(Millions of Dollars)	
Balance as of January 1	$44.3	$55.5
Liabilities Settled	(4.4)	(14.0)
Accretion	2.4	2.8
Balance as of December 31	$42.3	$44.3

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 nine 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 $215.9 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 2013, 2012 and 2011 were $50.3 million, $45.8 million and $65.9 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	2013	2012	2011
	(Millions of Dollars)		
Current tax expense (benefit)	$25.2	$13.1	$(166.7