Wisconsin Energy Corporation

BUILDING A **LEADER** IN THE **ENERGY INDUSTRY** FOR **DECADES TO COME**

2014 Annual Report

Wisconsin Energy Corporation

Wisconsin Energy to acquire Integrys Energy Group for $9.1 billion in cash, stock and assumed debt — creating a leading Midwest electric and gas utility

- Larger, more diverse regulated utility company with the financial strength and technical depth to meet customers' future energy needs; creates 8th largest natural gas distribution company in America
- Companies reiterate commitment to Integrys' 5-year plan to invest up to $3.5 billion in infrastructure and operational initiatives to maintain high levels of reliability and improve customer service
- Combined company will have majority ownership of American Transmission Company, LLC
- Integrys shareholders to receive a 17.3 percent premium to Integrys' closing price on June 20, 2014, and a 22.8 percent premium to the volume-weighted average share price over the past 30 trading days
- Integrys to divest Integrys Energy Services
- Positions Wisconsin Energy to deliver enhanced earnings growth; accretive to Wisconsin Energy's earnings per share in first full calendar year after closing

MILWAUKEE and CHICAGO – June 23, 2014 – Wisconsin Energy Corp. (NYSE: WEC) and Integrys Energy Group Inc. (NYSE: TEG) today announced that they have entered into a definitive agreement under which Wisconsin Energy will acquire Integrys in a transaction valued at $9.1 billion. Upon completion of the transaction, the combined company will be named WEC Energy Group, Inc.

The combination of Wisconsin Energy and Integrys brings together two strong utility systems with the operational expertise, scale and financial resources to meet the region's future energy needs.

The combined entity is projected to have a regulated rate base of $16.8 billion in 2015, serve more than 4.3 million total gas and electric customers across Wisconsin, Illinois, Michigan and Minnesota, and operate nearly 71,000 miles of electric distribution lines and more than 44,000 miles of gas transmission and distribution lines. The combination brings together Wisconsin Energy's top-performing electric and gas utility — We Energies — and Integrys' strong electric and gas utilities — Wisconsin Public Service, Peoples Gas, North Shore Gas, Minnesota Energy Resources and Michigan Gas Utilities.

TOTAL SHAREHOLDER RETURN

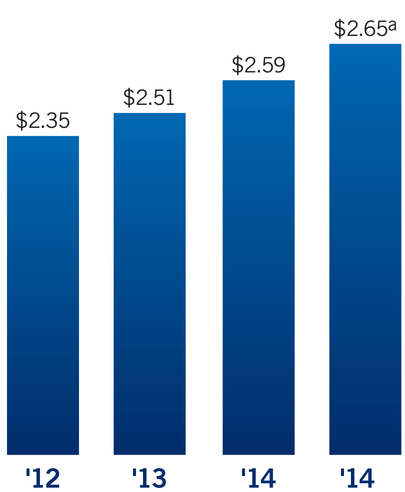
Over the past decade, our total shareholder return has outperformed the investment returns of the Dow Jones Industrials, the S&P 500, NASDAQ and all the major utility indexes.

TEN-YEAR PERFORMANCE (2005–2014)*	
WISCONSIN ENERGY	**317.9%**
Dow Jones Utilities Average	171.3%
Philadelphia Utility Index	142.4%
S&P Electric Index	140.9%
Dow Jones Industrial Average	114.1%
S&P 500 Index	109.5%
NASDAQ Composite Index	142.8%

*Stock price appreciation plus reinvested dividends.

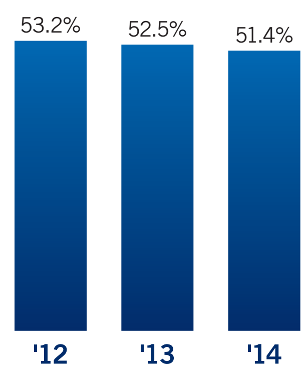
FINANCIAL HIGHLIGHTS

EARNINGS PER SHARE



DIVIDENDS PER SHARE[b]

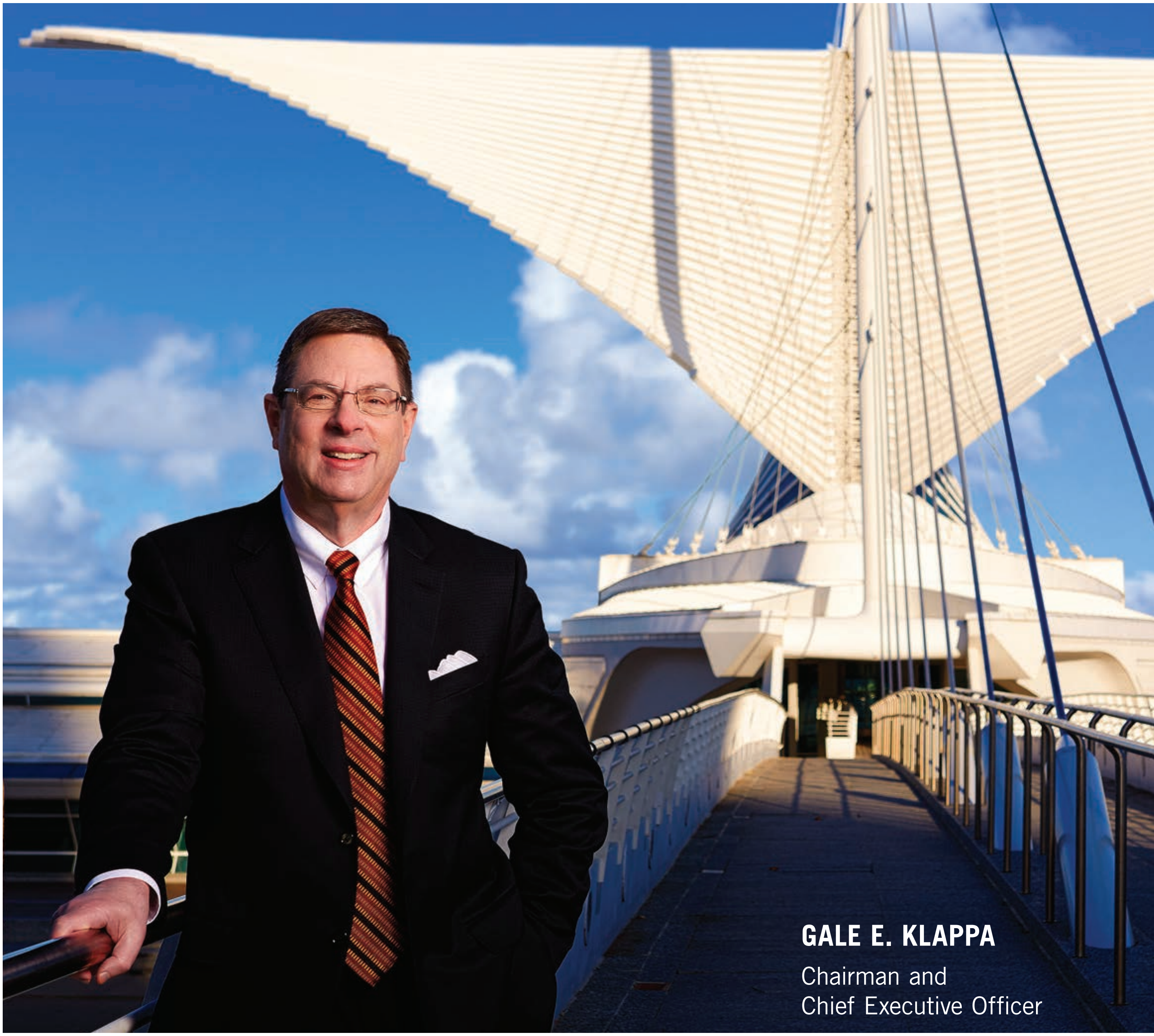
YEAR-END DEBT TO TOTAL CAPITAL[c]



a. Adjusted earnings per share. Excludes acquisition-related costs totaling 6 cents per share.

b. The quarterly dividend was increased from 39 cents per share to 42.25 cents per share in the first quarter of 2015.

c. Attributes $250 million of 2007 Series A Junior Subordinated Notes to common equity. A majority of the rating agencies currently attribute at least 50% common equity to these securities. For further details, see page F-17.



TO OUR STOCKHOLDERS,

It was quite a year …

- We delivered record financial results.
- Our stock price rose by more than 27 percent, setting 29 new all-time highs.
- Our total shareholder return was 32.1 percent — surpassing the performance of all of the major utility indexes.
- We raised our dividend payment by 8 percent.
- We were named the most reliable utility in the Midwest again — extending our strong track record of network reliability and customer satisfaction.
- We achieved the safest year of operation in more than 100 years of record keeping.
- We invested nearly $740 million in our core business, with all major projects on time and on budget.
- We completed 2014 with the strongest balance sheet in 17 years.
- And we were honored as one of the 100 best corporate citizens in the United States.

In addition to these achievements, 2014 will stand out as one of the most eventful and transformative years

in our history for another important reason. On June 23, we announced our plan to acquire Integrys Energy Group in a cash and stock transaction valued at $9.1 billion.

Combining Wisconsin Energy and Integrys — to form the WEC Energy Group — will create a strong electric and natural gas delivery company with deep operational expertise, scale, and the financial resources to meet the region's future energy needs. The combined company will serve more than 4.3 million customers in Wisconsin, Illinois, Michigan, and Minnesota and will become the 8th largest natural gas distribution company in the United States.

Our customers will benefit from the efficiency that comes with increased scale and geographic proximity. And, over time, we will enhance the operations of the seven utilities that will be part of our energy group by incorporating best practices systemwide.

In addition, Integrys is one of the major owners of American Transmission Company, with a 34.1 percent interest. Wisconsin Energy is the second largest owner with a 26.2 percent interest. The combined entity will have a 60 percent stake in one of the largest transmission companies in the country. We welcome the opportunity to increase our commitment to the transmission business.

2014 will stand out as one of the most eventful and transformative years in our history

As many of you know, we have consistently used three criteria to evaluate any potential acquisition opportunity. First, we would have to believe that the acquisition would add to earnings per share in the first full calendar year after closing. Second, it would need to have a largely neutral impact on our credit ratings. And finally, we would have to believe that the long-term growth rate of any acquisition would be at least equal to Wisconsin Energy's stand-alone growth rate.

Our analysis shows that this combination meets or exceeds all three criteria. We expect that the combined company will be able to grow earnings per share at 5 to 7 percent per year, faster than either one of us is projecting on a stand-alone basis. And, importantly, more than 99 percent of these earnings would come from regulated businesses.

We expect that the combined company will be able to grow earnings per share at 5 to 7 percent per year

Of course, the transaction requires stockholder approval and the approval of several regulatory agencies. I'm pleased to report that we're making progress on all fronts.

As you may recall, the stockholders of both companies approved the acquisition on November 21 of last year. In addition, the U.S. Department of Justice completed its review on October 24, with no further action required by the company.

We expect rulings from the Federal Energy Regulatory Commission and the commissions in Wisconsin, Illinois, Michigan, and Minnesota between now and early July. Following all necessary approvals, we plan to close the transaction during the second half of 2015.

In a related development, we reached an important settlement in January that will help resolve the electric reliability issues in the Upper Peninsula of Michigan and pave the way for approval of our acquisition by Michigan state authorities. The settlement calls for the sale of electric distribution assets in the Upper Peninsula that are owned by both Integrys and Wisconsin Energy. We would also transfer our Presque Isle Power Plant to Upper Peninsula Power Company. This arrangement will result in a larger, Michigan-based electric utility that can better plan to meet the longer-term needs of the Upper Peninsula.

DIVIDEND STRATEGY

At its January 2015 meeting, our board of directors raised the quarterly dividend on Wisconsin Energy common stock to 42.25 cents a share — an increase of 8.3 percent over the dividend paid during 2014. The new quarterly dividend is equivalent to an annual rate of $1.69 a share. The board reaffirmed our stand-alone dividend policy that targets a dividend payout ratio of 65 to 70 percent of earnings in 2017 — a level more competitive with our peers across the regulated utility sector.

When we close the Integrys acquisition, we expect to increase our dividend again — by 7 to 8 percent for Wisconsin Energy stockholders — to reflect the dividend policy of the combined company. Going forward, the payout target for the combined company is expected to be 65 to 70 percent of earnings.

IMPORTANT INFRASTRUCTURE INVESTMENTS TO CONTINUE

Looking ahead, we see significant investment opportunities in our existing core business as we continue to upgrade our aging distribution networks and focus on delivering the future.

Wisconsin Energy's capital budget calls for spending $3.3 billion to $3.5 billion over the five-year period 2015 to 2019. Our rolling 10-year capital budget calls for investing between $6.6 billion and $7.2 billion over the period 2015 through 2024.

And I'm pleased to report that we made excellent progress on several major infrastructure projects during 2014.

We see significant investment opportunities in our existing core business

West Central Gas Expansion Project Last July, we received approval from the Wisconsin Public Service Commission to build and operate a new natural gas lateral in west central Wisconsin. The 85 miles of pipeline and connected facilities will run from northern Eau Claire County, in the far western part of Wisconsin, to the city of Tomah, in the west central section of the state. The project is the largest single expansion in the history of our natural gas distribution business. It will help meet the growing demand for natural gas by customers who are converting from propane and also help serve the sand mining industry in the region.

Field work began in October, and we expect to complete the entire project in the fourth quarter of this year at an estimated cost of $175 million to $185 million.

The project is the largest single expansion in the history of our natural gas distribution business

Twin Falls At our Twin Falls hydroelectric plant on the Menominee River between Wisconsin and Michigan's Upper Peninsula, we're building a new powerhouse and adding spillway capacity to meet current federal standards. Built in 1912, Twin Falls is one of 13 hydroelectric plants on our system. The project is approximately 40 percent complete, and we're projecting commercial operation for the

Chairman and Chief Executive Gale Klappa and President Allen Leverett at Discovery World in Milwaukee.

summer of 2016. The total investment is budgeted at $60 million to $65 million.

Valley Power Plant Near downtown Milwaukee, conversion of our Valley Power Plant from coal to natural gas is progressing well. The two-unit plant generates electricity, produces steam for more than 400 customers in the downtown Milwaukee business center, and provides voltage support for the grid.

Converting Valley to natural gas will reduce our operating costs and enhance the environmental performance of the units.

Unit 1 achieved commercial operation burning natural gas in November. Conversion of Unit 2 should be completed later this year before the start of the winter heating season. Total conversion costs are expected to be $65 million to $70 million.

Oak Creek Expansion At our Oak Creek Expansion units, we're focused on our initiative to improve fuel flexibility. The units were initially permitted to burn bituminous coal, but given the current cost differential between bituminous coal and Powder River Basin coal — blending the two types of fuel could save our customers $25 million to $50 million a year, depending on the blend.

We're awaiting approval from the Wisconsin Commission to make additional investments in plant modifications, equipment, and storage capability to support sustained operations with higher levels of Powder River Basin coal. Together, these investments could total $80 million and provide significant benefits to our customers through lower fuel costs.

IN SUMMARY

Centuries ago, the philosopher Aristotle wrote that excellence is not a single act ... but a habit.

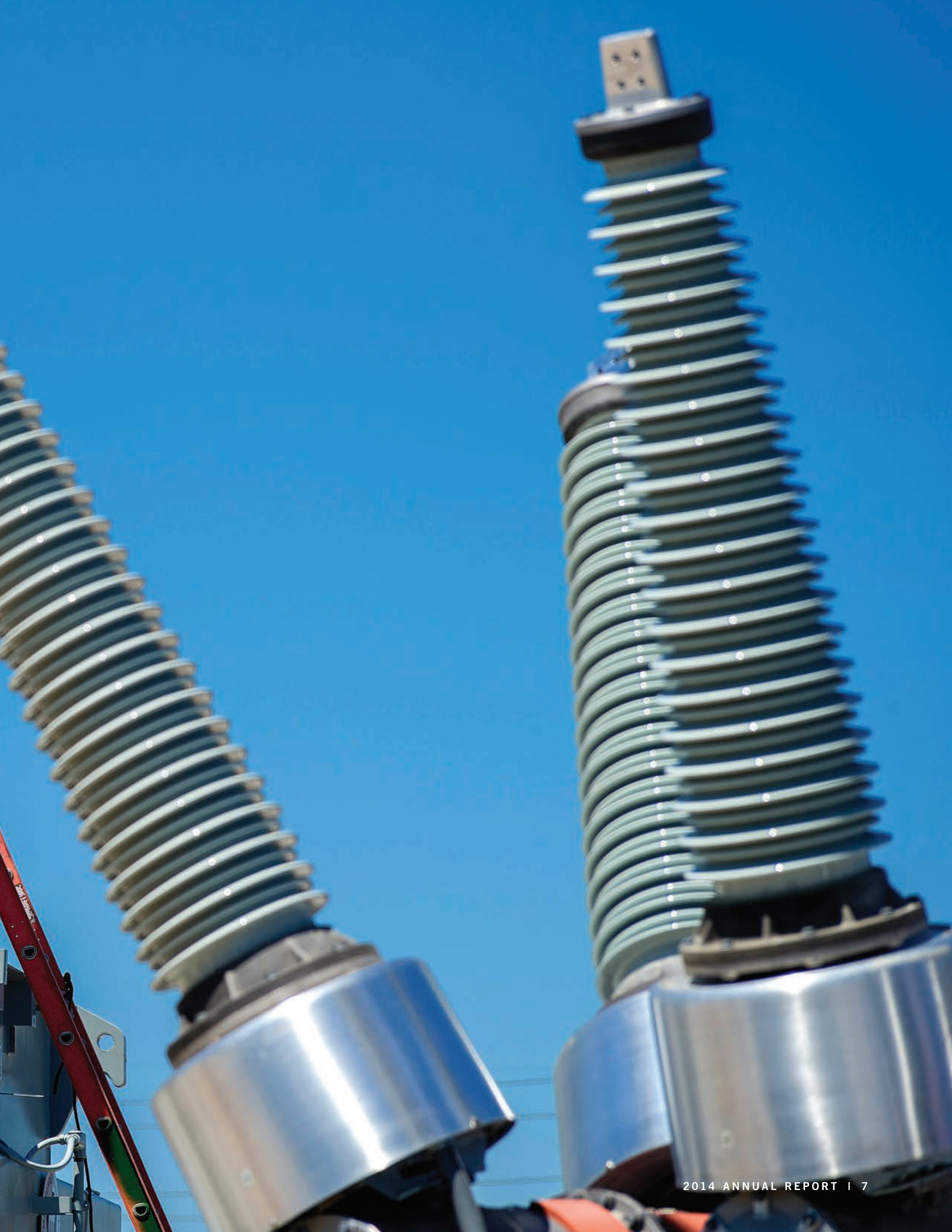
Please know that our management team will continue to pursue excellence in the year ahead as we build a leader in the energy industry for decades to come.

Sincerely,

Gale E. Klappa
Chairman and Chief Executive Officer
March 4, 2015

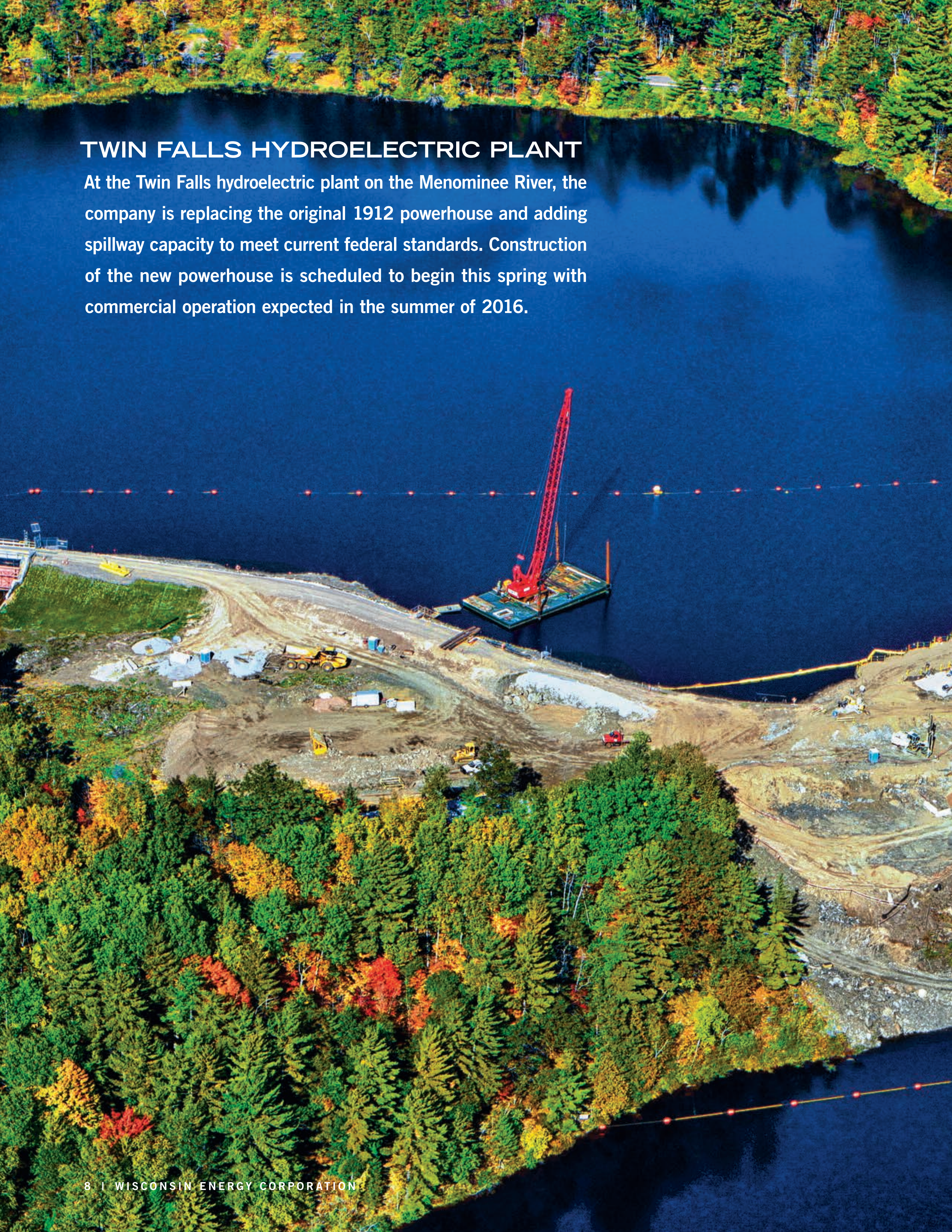
IMPROVING RELIABILITY

A worker guides a 71-ton transformer into place at the Lincoln Substation in Milwaukee. The substation was rebuilt last summer to maintain a high level of reliability for nearly 25,000 customers, including the major industrial and manufacturing companies on Milwaukee's west side.



TWIN FALLS HYDROELECTRIC PLANT

At the Twin Falls hydroelectric plant on the Menominee River, the company is replacing the original 1912 powerhouse and adding spillway capacity to meet current federal standards. Construction of the new powerhouse is scheduled to begin this spring with commercial operation expected in the summer of 2016.



PROUD TO BE THE MOST RELIABLE UTILITY

#1 in the Midwest ... again

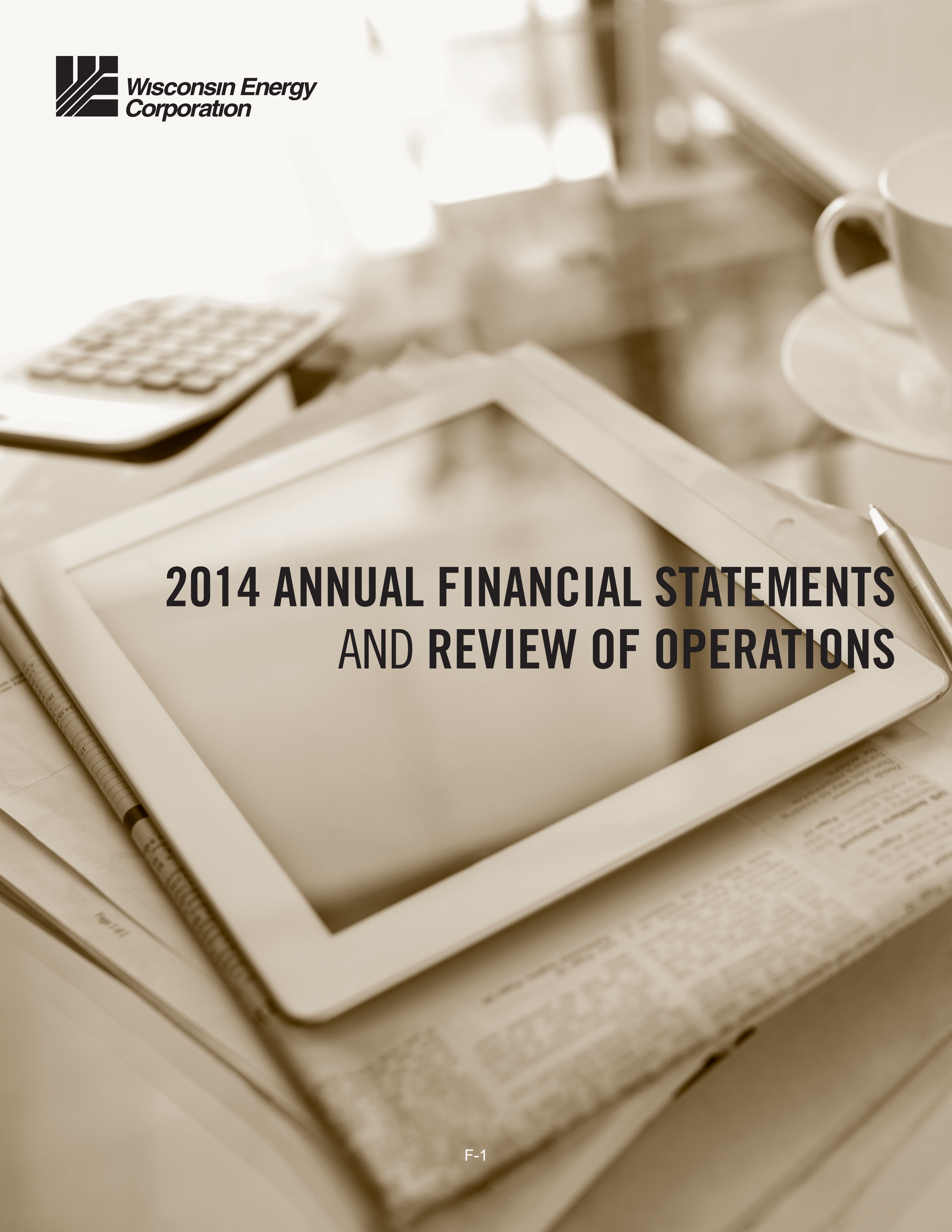
BEST IN THE MIDWEST ... AGAIN

For the fourth year in a row, We Energies received the ReliabilityOne™ Award in the Midwest for the superior reliability of its electric system.

The award is a testament to our employees, who focus every day on delivering outstanding customer care. It also reflects the significant investments we've made in recent years to upgrade critical infrastructure and strengthen the reliability of our network.

Wisconsin Energy Corporation

2014 ANNUAL FINANCIAL STATEMENTS AND REVIEW OF OPERATIONS



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DEFINITION OF ABBREVIATIONS AND INDUSTRY TERMS

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

Primary Subsidiaries	
We Power	W.E. Power, LLC
Wisconsin Electric	Wisconsin Electric Power Company
Wisconsin Gas	Wisconsin Gas LLC
Significant Assets	
OC 1	Oak Creek expansion Unit 1
OC 2	Oak Creek expansion Unit 2
PIPP	Presque Isle Power Plant
PSGS	Paris Generating Station
PWGS 1	Port Washington Generating Station Unit 1
PWGS 2	Port Washington Generating Station Unit 2
VAPP	Valley Power Plant
Other Subsidiaries and Affiliates	
ATC	American Transmission Company LLC
ERGSS	Elm Road Generating Station Supercritical, LLC
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
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
CAIR	Clean Air Interstate Rule
CO_2	Carbon Dioxide
CSAPR	Cross-State Air Pollution Rule
EM	Entrainment Mortality
GHG	Greenhouse Gas
IM	Impingement Mortality
MATS	Mercury and Air Toxics Standards
NAAQS	National Ambient Air Quality Standards
NO_x	Nitrogen Oxide
$PM_{2.5}$	Fine Particulate Matter
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
WPDES	Wisconsin Pollutant Discharge Elimination System

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:

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
Exchange Act	Securities Exchange Act of 1934, as amended
Fitch	Fitch Ratings
FTRs	Financial Transmission Rights
GCRM	Gas Cost Recovery Mechanism
HSR Act	Hart-Scott-Rodino Antitrust Improvements Act of 1976
Integrys	Integrys Energy Group, Inc.
Junior Notes	Wisconsin Energy's 2007 Series A Junior Subordinated Notes due 2067
LMP	Locational Marginal Price
Merger Agreement	Agreement and Plan of Merger, dated as of June 22, 2014, between Integrys and Wisconsin Energy Corporation
MISO	Midcontinent Independent System Operator, Inc.
MISO Energy Markets	MISO Energy and Operating Reserves Market
Moody's	Moody's Investor Service
OTC	Over-the-Counter
Point Beach	Point Beach Nuclear Power Plant
PTF	Power the Future
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
UPPCO	Upper Peninsula Power Company
Measurements	
Btu	British Thermal Unit(s)
Dth	Dekatherm(s) (One Dth equals one million Btu)
kW	Kilowatt(s) (One kW equals one thousand Watts)
kWh	Kilowatt-hour(s)
MW	Megawatt(s) (One MW equals one million Watts)
MWh	Megawatt-hour(s)
Watt	A measure of power production or usage
Accounting Terms	
AFUDC	Allowance for Funds Used During Construction
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," "could," "estimates," "expects," "forecasts," "goals," "guidance," "intends," "may," "objectives," "plans," "possible," "potential," "projects," "seeks," "should," "targets," "will" 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 damage; availability of electric generating facilities; unscheduled generation outages, or unplanned maintenance or repairs; unanticipated events causing scheduled generation outages to last longer than expected; unanticipated changes in fossil fuel, purchased power, coal supply, gas supply or water supply costs or availability due to higher demand, shortages, transportation problems or other developments; 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.

- The impact across our service territories of the continued adoption of distributed generation by our electric customers.

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

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

- 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; adoption of new, or changes in existing, environmental, federal and state energy, tax and other laws and regulations to which we are, or may become, 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.
- Events in the global credit markets that may affect the availability and cost of capital.
- Other factors affecting our ability to access the capital markets, including general capital market conditions; our capitalization structure; market perceptions of the utility industry, us or any of our subsidiaries; and our credit ratings.
- The direct or indirect effect on our business resulting from terrorist incidents and the threat of terrorist incidents, including cyber intrusion.
- 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 to obtain the required approvals for their transmission projects.
- 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.
- The expected timing and likelihood of completion of the proposed acquisition of Integrys Energy Group, Inc. (Integrys), including the timing, receipt and terms and conditions of any required governmental and regulatory approvals of the proposed acquisition that could reduce anticipated benefits or cause the parties to abandon the acquisition, the ability to successfully integrate the businesses, the ability to secure necessary financing on favorable terms, and the risk that the credit ratings of the combined company or its subsidiaries may differ from what we expect.
- 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.

BUSINESS OF THE COMPANY

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 1,133,600 electric customers in Wisconsin and the Upper Peninsula of Michigan. We Energies serves approximately 1,089,000 gas customers in Wisconsin and approximately 440 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. 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 Management's Discussion and Analysis and Note O -- Segment Reporting in the Notes to Consolidated Financial Statements.

Proposed Acquisition: On June 22, 2014, we entered into an agreement to acquire Integrys. The proposed acquisition is scheduled to close in the second half of 2015, and is subject to the receipt of various approvals. The combined company will serve approximately 1.5 million electric customers, 2.8 million gas customers, and own approximately 60% of ATC. For additional information on this acquisition, see Corporate Strategy in Management's Discussion and Analysis and Note D -- Proposed Acquisition in the Notes to Consolidated Financial Statements.

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

CORPORATE DEVELOPMENTS AND STRATEGY

Acquisition: On June 22, 2014, we entered into an agreement to acquire Integrys. The proposed acquisition is scheduled to close in the second half of 2015, and is subject to the receipt of various approvals. This acquisition is in alignment with our corporate strategy to invest in regulated electric and gas businesses. We expect the acquisition to:

- Add approximately $6.6 billion of regulated fixed assets;
- Add 0.5 million electric customers;
- Add 1.7 million gas customers; and
- Increase our ownership of ATC to 60% from 26.2%.

For additional information on this acquisition, see Note D -- Proposed Acquisition in the Notes to Consolidated Financial Statements.

Additional Investment Opportunities: Our primary investment opportunities are in three areas: 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 2014, our regulated utility earned $770.2 million of operating income. Over the next five years, we currently expect to invest between $3.2 billion and $3.4 billion in this business.

We have a 26.2% ownership interest in ATC, a Midcontinent Independent System Operator, Inc. (MISO) member company regulated by Federal Energy Regulatory Commission (FERC). Our investment in ATC totaled $424.1 million as of December 31, 2014, and our 2014 pre-tax earnings from ATC totaled $66.0 million. Over the next five years, in addition to any potential investment through our undistributed earnings in ATC, on a stand-alone basis 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 $368.2 million during 2014. Over the next five years, we expect to invest approximately $130 million in this segment. These investments should provide additional earnings.

RESULTS OF OPERATIONS

CONSOLIDATED EARNINGS

The following table compares our operating income by business segment and our net income for 2014, 2013 and 2012:

Wisconsin Energy Corporation	2014	2013	2012
		(Millions of Dollars)	
Utility Energy	$ 770.2	$ 719.4	$ 647.7
Non-Utility Energy	368.2	367.1	358.8
Corporate and Other (a)	(26.3)	(6.4)	(6.2)
Total Operating Income	1,112.1	1,080.1	1,000.3
Equity in Earnings of Transmission Affiliate	66.0	68.5	65.7
Other Income and Deductions, net	13.4	18.8	34.8
Interest Expense, net	241.5	252.1	248.2
Income Before Income Taxes	950.0	915.3	852.6
Income Tax Expense	361.7	337.9	306.3
Net Income	$ 588.3	$ 577.4	$ 546.3
Diluted Earnings Per Share	$ 2.59	$ 2.51	$ 2.35

(a) External costs related to the proposed acquisition of Integrys reduced our 2014 earnings by $0.06 per share.

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 2014, 2013 and 2012:

Utility Energy Segment	2014	2013	2012
		(Millions of Dollars)	
Operating Revenues			
Electric	$ 3,401.1	$ 3,308.7	$ 3,193.9
Gas	1,496.1	1,113.7	962.6
Other	44.1	39.6	34.3
Total Operating Revenues	4,941.3	4,462.0	4,190.8
Operating Expenses			
Fuel and Purchased Power	1,228.1	1,158.1	1,103.8
Cost of Gas Sold	1,036.1	674.1	545.8
Other Operation and Maintenance	1,462.7	1,522.0	1,476.5
Depreciation and Amortization	340.6	320.2	296.4
Property and Revenue Taxes	121.0	116.2	120.6
Total Operating Expenses	4,188.5	3,790.6	3,543.1
Treasury Grant	17.4	48.0	—
Operating Income	$ 770.2	$ 719.4	$ 647.7

An analysis of the utility energy segment follows.

Electric Utility Gross Margin

The following table compares our electric utility gross margin during 2014 with similar information for 2013 and 2012, including a summary of electric operating revenues and electric sales by customer class:

Electric Utility Operations	Electric Revenues and Gross Margin 2014	2013	2012	MWh Sales 2014	2013	2012
	(Millions of Dollars)			(Thousands)		
Customer Class						
Residential	$ 1,199.3	$ 1,208.6	$ 1,163.9	7,946.3	8,141.9	8,317.7
Small Commercial/Industrial	1,052.9	1,048.0	1,013.6	8,805.1	8,860.4	8,860.0
Large Commercial/Industrial	637.0	711.9	744.3	7,393.3	8,673.4	9,710.7
Other - Retail	23.0	23.4	22.8	148.7	152.3	154.8
Total Retail	2,912.2	2,991.9	2,944.6	24,293.4	25,828.0	27,043.2
Wholesale - Other	131.9	143.7	144.4	1,852.8	1,953.5	1,566.6
Resale - Utilities	264.1	143.2	53.4	6,497.9	4,382.7	1,642.4
Other Operating Revenues	87.8	28.4	51.5	—	—	—
Total	3,396.0	3,307.2	3,193.9	32,644.1	32,164.2	30,252.2
Electric Customer Choice (a)	5.1	1.5	—	2,440.0	813.0	—
Total, including electric customer choice	3,401.1	3,308.7	3,193.9			
Fuel and Purchased Power						
Fuel	656.6	611.1	541.6			
Purchased Power	557.4	533.4	548.7			
Total Fuel and Purchased Power	1,214.0	1,144.5	1,090.3			
Total Electric Gross Margin	$ 2,187.1	$ 2,164.2	$ 2,103.6			
Weather - Degree Days (b)						
Heating (6,601 Normal)				7,616	7,233	5,704
Cooling (732 Normal)				464	688	1,041

(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

2014 vs. 2013: Our electric utility operating revenues increased by $92.4 million, or 2.8%, when compared to 2013. The most significant factors that caused a change in revenues were:

- A $120.9 million increase in sales for resale because of increased sales into the MISO Energy Markets as a result of Michigan's alternative electric supplier program and increased availability of our generating units. The margin on these sales is used to reduce fuel costs for our retail customers.
- A $78.4 million decrease in large commercial/industrial sales because of the two iron ore mines switching to an alternative electric supplier in September 2013. See Factors Affecting Results, Liquidity and Capital Resources -- Industry Restructuring and Competition -- Michigan Business, for a discussion of the impact of industry restructuring in Michigan on our electric sales.
- A $59.4 million increase in other operating revenues, primarily driven by the recognition of $56.4 million related to revenues under the System Support Resource (SSR) agreement with MISO. See Factors Affecting Results, Liquidity and Capital Resources -- Industry Restructuring and Competition -- Michigan Business -- SSR Payments for further discussion.
- Wisconsin net retail pricing increases of $38.3 million, which are primarily related to our 2013 Wisconsin Rate Case.
- Unseasonably cool summer weather which decreased electric revenues by an estimated $45.8 million.

As measured by cooling degree days, 2014 was 36.6% cooler than normal, and 32.6% cooler than 2013 due to mild second and third quarters. The unfavorable impact of the cool summer weather was partially offset by the cold winter weather. Residential sales decreased by 2.4%, primarily due to the weather. Sales to our large commercial/industrial customers decreased by 14.8% primarily because of the loss of the two iron ore mines in Michigan. If the mines are excluded, sales to our large commercial/industrial customers decreased 1.1%. 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 switched to an alternative electric supplier.

Effective February 1, 2015, the two mines returned as retail customers. We expect to defer the net revenue from those sales and apply these amounts for the benefit of Wisconsin retail electric customers in future rate proceedings. Michigan state law allows the mines to switch to an alternative electric supplier after sufficient notice.

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 are 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.
- An $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.
- A $23.1 million decrease in other operating revenues, primarily driven by the amortization of $25.9 million in 2012 related to proceeds we received as part of a settlement with the United States Department of Energy (DOE) regarding the DOE's failure to remove spent nuclear fuel from Point Beach Nuclear Power Plant (Point Beach).
- A return to more normal summer weather as compared to 2012 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 the loss of the two iron ore mines in Michigan. If the mines are excluded, sales to our large commercial/industrial customers decreased 3.0%. 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.

Electric Fuel and Purchased Power Expenses

2014 vs. 2013: Our electric fuel and purchased power costs increased by $69.5 million, or approximately 6.1%, when compared to 2013. This increase was primarily caused by a 1.5% increase in total MWh sales and higher generating costs driven by an increase in natural gas prices.

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.

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 2014, 2013 and 2012.

Gas Utility Operations	2014	2013	2012
	(Millions of Dollars)		
Operating Revenues	$ 1,496.1	$ 1,113.7	$ 962.6
Cost of Gas Sold	1,036.1	674.1	545.8
Gross Margin	$ 460.0	$ 439.6	$ 416.8

We believe gross margin is a better performance indicator than revenues because changes in the cost of gas sold flow through to revenue under Gas Cost Recovery Mechanisms (GCRMs). Our average cost of gas per therm during 2014, 2013 and 2012 was $0.70, $0.48 and $0.50, respectively. The following table compares our gas utility gross margin and therm deliveries by customer class during 2014, 2013 and 2012:

Gas Utility Operations	Gross Margin			Therm Deliveries		
	2014	2013	2012	2014	2013	2012
	(Millions of Dollars)			(Millions)		
Customer Class						
Residential	$ 291.8	$ 284.2	$ 267.9	911.5	872.0	676.4
Commercial/Industrial	104.6	96.5	88.8	553.1	499.9	390.6
Interruptible	1.9	1.8	1.7	18.6	18.1	14.6
Total Retail	398.3	382.5	358.4	1,483.2	1,390.0	1,081.6
Transported Gas	55.1	51.7	52.9	1,087.5	1,052.8	1,140.4
Other Operating	6.6	5.4	5.5	—	—	—
Total	$ 460.0	$ 439.6	$ 416.8	2,570.7	2,442.8	2,222.0
Weather - Degree Days (a)						
Heating (6,601 Normal)				7,616	7,233	5,704

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

2014 vs. 2013: Our total retail gas margin increased by $15.8 million, or approximately 4.1%, when compared to 2013, primarily because of colder winter weather in 2014. We estimate that colder winter weather increased gas margins by approximately $11.2 million. As measured by heating degree days, 2014 was 5.3% colder than 2013 and 15.4% colder than normal.

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.

Other Operation and Maintenance Expense

2014 vs. 2013: Our other operation and maintenance expense decreased by $59.3 million, or approximately 3.9%, when compared to 2013. This decrease was primarily driven by lower benefit costs related to pensions and medical costs.

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

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.

Depreciation and Amortization Expense

2014 vs. 2013: Depreciation and Amortization expense increased by $20.4 million, or approximately 6.4%, when compared to 2013. This increase was primarily because of an overall increase in utility plant in service as a result of the biomass plant that went into service in November 2013. For additional information on the biomass facility, see Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters -- Renewables, Efficiency, and Conservation.

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. In addition to the biomass facility that went into service in November 2013, 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.

Treasury Grant

During 2014, we recognized $17.4 million of income related to a Treasury Grant associated with the completion of the biomass plant, compared to $48.0 million in 2013. The lower grant income corresponds to the lower bill credits provided to our retail electric customers in Wisconsin in 2014. For additional information on the Treasury Grant, see Factors Affecting Results, Liquidity and Capital Resources -- Accounting Developments.

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 PTF 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.

	2014	2013	2012
	(Millions of Dollars)		
Operating Revenues	$ 447.1	$ 446.7	$ 439.9
Operation and Maintenance Expense	11.4	12.5	14.0
Depreciation Expense	67.5	67.1	67.1
Operating Income	$ 368.2	$ 367.1	$ 358.8

2014 vs. 2013: Non-utility energy segment operating income increased $1.1 million, or approximately 0.3%, when compared to 2013.

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.

CORPORATE AND OTHER CONTRIBUTION TO OPERATING INCOME

2014 vs. 2013: Corporate and other affiliates had an operating loss of $26.3 million in 2014 compared with an operating loss of $6.4 million in 2013. The increase in operating loss is primarily attributable to approximately $14.6 million, or $0.06 per share, of external costs related to the proposed acquisition of Integrys.

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.

CONSOLIDATED OTHER INCOME AND DEDUCTIONS, NET

Other Income and Deductions, net	2014	2013	2012
	(Millions of Dollars)		
AFUDC - Equity	$ 5.6	$ 18.3	$ 35.3
Gain on Property Sales	7.5	0.8	2.7
Other, net	0.3	(0.3)	(3.2)
Total Other Income and Deductions, net	$ 13.4	$ 18.8	$ 34.8

2014 vs. 2013: Other income and deductions, net decreased by approximately $5.4 million, or 28.7%, when compared to 2013. This decrease primarily relates to lower AFUDC - Equity related to the biomass plant going into service in November 2013, partially offset by an increased gain on property sales.

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.

CONSOLIDATED INTEREST EXPENSE, NET

Interest Expense, net	2014	2013	2012
	(Millions of Dollars)		
Gross Interest Costs	$ 244.5	$ 261.5	$ 264.1
Less: Capitalized Interest	3.0	9.4	15.9
Interest Expense, net	$ 241.5	$ 252.1	$ 248.2

2014 vs. 2013: Our net interest expense decreased by $10.6 million, or 4.2%, as compared to 2013 primarily because of lower debt levels and lower average interest rates on long-term debt. Our capitalized interest decreased by $6.4 million primarily because of lower construction work in progress as the biomass plant went into service in November 2013.

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.

CONSOLIDATED INCOME TAX EXPENSE

2014 vs. 2013: Our effective tax rate applicable to continuing operations was 38.1% in 2014 compared to 36.9% in 2013. This increase in our effective tax rate was due to reduced tax benefits associated with Treasury Grant income, decreased AFUDC - Equity and non-deductible acquisition related expenses. For further information, see Note G -- Income Taxes in the Notes to Consolidated Financial Statements. We expect our 2015 annual effective tax rate to be between 37.0% and 38.0%.

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.

LIQUIDITY AND CAPITAL RESOURCES

CASH FLOWS

The following table summarizes our cash flows during 2014, 2013 and 2012:

	2014	2013	2012
		(Millions of Dollars)	
Cash Provided by (Used in)			
Operating Activities	$ 1,197.7	$ 1,231.0	$ 1,173.9
Investing Activities	$ (756.8)	$ (745.8)	$ (729.6)
Financing Activities	$ (405.0)	$ (494.8)	$ (422.8)

Operating Activities

2014 vs. 2013: Cash provided by operating activities was $1,197.7 million during 2014, which was a decrease of $33.3 million when compared to 2013. During 2014, we experienced higher net income, depreciation expense and favorable cash flows from accounts receivable, primarily because of the timing of the Treasury Grant. More than offsetting these favorable items were increases in working capital related to natural gas in storage and increases in regulatory assets.

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.

Investing Activities

2014 vs. 2013: Cash used in investing activities was $756.8 million during 2014, which was $11.0 million higher than 2013. This increase was driven by an increase of $48.7 million in capital expenditures, primarily because of starting the conversion of the fuel source for Valley Power Plant (VAPP) from coal to natural gas. This increase in cash used in investing activities was partially offset by an increase in proceeds received from asset sales and a decrease of cost of removal, net of salvage.

The following table identifies capital expenditures by year:

Capital Expenditures	2014	2013	2012
		(Millions of Dollars)	
Utility	$ 689.9	$ 657.9	$ 697.3
We Power	41.1	26.1	5.5
Other	5.1	3.4	4.2
Total Capital Expenditures	$ 736.1	$ 687.4	$ 707.0

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 proceeds we received from the settlement with the DOE. 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.

Financing Activities

The following table summarizes our cash flows from financing activities:

	2014	2013	2012
	(Millions of Dollars)		
Dividends on Common Stock	$ (352.0)	$ (328.9)	$ (276.3)
Common Stock Repurchased, Net	(72.9)	(174.9)	(103.4)
Net Increase (Decrease) in Debt	5.9	(3.4)	(43.8)
Other	14.0	12.4	0.7
Cash Used in Financing	$ (405.0)	$ (494.8)	$ (422.8)

2014 vs. 2013: Cash used in financing activities was $405.0 million during 2014, compared to $494.8 million during 2013. The decrease in cash used in financing activities was primarily driven by a decrease in common stock repurchased as a result of our Board of Directors terminating our share repurchase program in connection with the proposed acquisition of Integrys. During 2014, we repurchased $18.6 million of common stock as compared to $126.0 million in 2013 as part of the share repurchase program. See Note H -- Common Equity for additional information on share repurchases. Our dividends paid on common stock increased by $23.1 million during 2014 as compared to 2013, as a result of increases in the quarterly common stock dividend of 12.5% and 2.0% in the third quarter of 2013 and first quarter of 2014, respectively.

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 2013, we repurchased approximately 3.0 million shares in the open market at a total cost of $126.0 million, compared to 1.5 million shares at a cost of $51.8 million in 2012 pursuant to a share repurchase program that expired at the end of 2013.

No new shares of Wisconsin Energy's common stock were issued in 2014, 2013 or 2012. During these years, our independent plan agents purchased, in the open market, 2.3 million shares at a cost of $104.6 million, 2.4 million shares at a cost of $97.4 million and 2.8 million shares at a cost of $101.4 million, respectively, to fulfill exercised stock options and restricted stock awards. In 2014, 2013 and 2012, we received proceeds of $50.3 million, $48.5 million and $49.8 million, respectively, related to the exercise of stock options. In addition, we instructed our independent agents to purchase shares of our common stock in the open market to satisfy our obligations under our stock purchase and dividend reinvestment plan and various employee benefit plans.

CAPITAL RESOURCES AND REQUIREMENTS

Working Capital

As of December 31, 2014, our current liabilities exceeded our current assets by approximately $133.3 million. We do not expect this to have any impact on our liquidity because we believe we have adequate back-up lines of credit in place for ongoing operations. We also have access to the capital markets to finance our construction program and to refinance current maturities of long-term debt if necessary.

Liquidity

We anticipate meeting our capital requirements for our existing operations through internally generated funds and short-term borrowings, supplemented by the issuance of intermediate or long-term debt securities.

For our existing business, 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, 2014, we had approximately $1.2 billion of available, undrawn lines under our bank back-up credit facilities. As of December 31, 2014, we had approximately $617.6 million of commercial paper outstanding on a consolidated basis that was supported by the available lines of credit. During 2014, our maximum commercial paper outstanding was $721.4 million with a weighted-average interest rate of 0.18%. For additional information regarding our commercial paper balances during 2014, 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, 2014:

Company	Total Facility	Letters of Credit	Credit Available	Facility Expiration
		(Millions of Dollars)		
Wisconsin Energy	$ 400.0	$ —	$ 400.0	December 2019
Wisconsin Electric	$ 500.0	$ 5.1	$ 494.9	December 2019
Wisconsin Gas	$ 350.0	$ —	$ 350.0	December 2019

In December 2014, we amended each of our credit facilities to extend their expirations from December 2017 to December 2019.

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, 2014 and 2013, 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):

	2014		2013	
Capitalization Structure	Actual	Adjusted	Actual	Adjusted
	(Millions of Dollars)			
Common Equity	$ 4,419.7	$ 4,669.7	$ 4,233.0	$ 4,483.0
Preferred Stock of Subsidiary	30.4	30.4	30.4	30.4
Long-Term Debt (including current maturities)	4,610.5	4,360.5	4,705.4	4,455.4
Short-Term Debt	617.6	617.6	537.4	537.4
Total Capitalization	$ 9,678.2	$ 9,678.2	$ 9,506.2	$ 9,506.2
Total Debt	$ 5,228.1	$ 4,978.1	$ 5,242.8	$ 4,992.8
Ratio of Debt to Total Capitalization	54.0%	51.4%	55.2%	52.5%

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, 2014 and 2013 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, 2014, the repurchased bonds were still outstanding, but were not reported as long-term debt or included on our Consolidated Statements of Capitalization because they are held by Wisconsin Electric. Depending on market conditions and other factors, Wisconsin Electric may change the method used to determine the interest rate on the bonds and have them remarketed to third parties.

Bonus Depreciation Provisions

The Tax Increase Prevention Act of 2014 was signed into law on December 19, 2014, which extended the 50% bonus depreciation rules to include assets placed in service in 2014. As a result of the increased federal tax depreciation for 2014 and prior years, we did not make federal income tax payments for 2013 and 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, 2014, we estimate that the collateral or the termination payments required under these agreements totaled approximately $198.0 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 December 2014, Moody's affirmed the ratings of Wisconsin Electric (senior unsecured, A1; commercial paper, P-1) and Wisconsin Gas (senior unsecured, A1; commercial paper, P-1). Moody's affirmed the stable ratings outlook for Wisconsin Electric and Wisconsin Gas. In June 2014, Moody's affirmed the ratings of Wisconsin Energy (senior unsecured, A2; junior subordinated, A3; commercial paper, P-1), Elm Road Generating Station Supercritical, LLC (ERGSS) (senior notes, A1) and Wisconsin Energy Capital Corporation (WECC) (senior unsecured, A2). Moody's also affirmed the stable ratings outlook for ERGSS, and revised the ratings outlook for Wisconsin Energy and WECC from stable to negative.

In August 2014, Fitch Ratings (Fitch) affirmed the ratings of Wisconsin Electric (commercial paper, F1; senior unsecured, A+), Wisconsin Gas (commercial paper, F1; senior unsecured, A) and ERGSS (senior notes, A+). Fitch also affirmed the stable ratings outlook for these companies. In June 2014, Fitch placed the ratings of Wisconsin Energy and WECC on Rating Watch Negative.

In June 2014, 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-1; senior unsecured, A) and WECC (senior unsecured, A-). S&P affirmed the stable ratings outlook for Wisconsin Electric and Wisconsin Gas, and revised the ratings outlook from stable to negative for Wisconsin Energy and WECC.

The change in outlooks for Wisconsin Energy and WECC relates to the proposed acquisition of Integrys.

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

Acquisition of Integrys: On June 22, 2014, we entered into an agreement to acquire Integrys. We expect the transaction to close in the second half of 2015. Under the terms of the Merger Agreement, for each share of Integrys common stock, Integrys shareholders will receive 1.128 shares of Wisconsin Energy common stock and $18.58 in cash. We expect to finance the acquisition through the issuance of approximately 91 million shares of Wisconsin Energy common stock to Integrys shareholders and through the issuance of $1.5 billion of debt. We will also assume all of Integrys' outstanding debt, which had an estimated fair value of $3.3 billion.

Capital Expenditures: For our existing business, our estimated capital expenditures for the next three years are as follows:

Capital Expenditures	2015	2016	2017
	(Millions of Dollars)		
Utility	$ 765.5	$ 627.6	$ 657.5
We Power	48.3	28.7	6.6
Other	13.9	5.5	0.2
Total	$ 827.7	$ 661.8	$ 664.3

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: In December 2013, our Board of Directors authorized a share repurchase program for up to $300 million of our common stock from January 1, 2014 through the end of 2017. Through December 31, 2014, we acquired approximately 0.4 million shares in the open market at a cost of $18.6 million pursuant to this program. All of these shares were purchased during the first quarter of 2014. On June 22, 2014, in connection with the proposed acquisition of Integrys, the Board of Directors terminated this share repurchase program.

In addition, on January 15, 2015, our Board of Directors increased our quarterly common stock dividend to $0.4225 per share, up approximately 8.3%, from $0.39 per share, effective with the first quarter 2015 dividend payment. This equates to an annual dividend of $1.69 per share. The Board of Directors reaffirmed a policy that targets a dividend payout ratio that trends to 65-70% of earnings in 2017.

Upon consummation of the proposed acquisition of Integrys, we expect to increase the dividend 7-8% for our shareholders to reflect the dividend policy of the combined company. The projected payout target for the combined company in future years after closing the acquisition is 65-70% of earnings.

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, 2014. These trusts hold investments that are subject to the volatility of the stock market and interest rates.

During 2014 and 2013, we made no contributions to our qualified pension plans or our qualified Other Post-Retirement Employee Benefit (OPEB) plans. In January 2015, we contributed $100 million to our qualified pension 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, 2014:

	Payments Due by Period				
Contractual Obligations (a)	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
	(Millions of Dollars)				
Long-Term Debt Obligations (b)	$ 8,716.4	$ 508.9	$ 592.2	$ 932.2	$ 6,683.1
Capital Lease Obligations (c)	174.0	43.5	59.0	30.2	41.3
Operating Lease Obligations (d)	38.1	5.2	7.1	4.3	21.5
Purchase Obligations (e)	11,707.9	879.5	1,310.3	1,093.3	8,424.8
Other Long-Term Liabilities	1,009.6	104.9	208.2	204.7	491.8
Total Contractual Obligations	$ 21,646.0	$ 1,542.0	$ 2,176.8	$ 2,264.7	$ 15,662.5

(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.

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 Public Service Commission of Wisconsin (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, 2014, our regulatory assets totaled $1,271.2 million and our regulatory liabilities totaled $830.6 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 2014 rate order, the PSCW authorized continued use of the escrow method of accounting for bad debt costs. 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 2014, 2013 and 2012, 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, 2014. 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, 2014 of our outstanding portfolio of commercial paper and variable rate long-term debt. As of December 31, 2014, we had $617.6 million of commercial paper outstanding with a weighted average interest rate of 0.22%. A one-percentage point change in interest rates would cause our annual interest expense to increase or decrease by approximately $6.2 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 and expected long-term returns were approximately:

	As of December 31, 2014 (Millions of Dollars)	Expected Return on Assets in 2015
Pension trust funds	$ 1,444.6	7.00%
Other post-retirement benefits trust funds	$ 333.5	7.25%

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. In addition, any economic downturn or disruption of national or international markets could adversely affect the financial condition of our customers and demand for their products, which could affect their demand for our products.

Inflation: We continue to monitor the impact of inflation, especially with respect to the costs of medical plans, fuel, transmission access, construction costs, and regulatory and environmental compliance 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.

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.

We are recovering our costs in these units, including subsequent capital additions, 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 Michigan Public Service Commission (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 the PTF units 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 Power Corporation (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. All warranty claims between the Company and Bechtel have now been resolved, none of which had a material impact on our financial statements.

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, 2014, we estimate that approximately 85% of our electric revenues were regulated by the PSCW, 2% were regulated by the MPSC and the balance of our electric revenues was regulated by FERC. In Wisconsin, a general rate case is typically filed every two years. All of our natural gas and steam revenues are regulated by the PSCW. Orders from the PSCW can be viewed at http://psc.wi.gov/ and orders from the MPSC can be viewed at www.michigan.gov/mpsc/.

General Rate Proceedings

2015 Wisconsin Rate Case: In May 2014, Wisconsin Electric and Wisconsin Gas applied to the PSCW for a biennial review of costs and rates. On December 23, 2014, 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 $2.7 million (0.1%) in 2015. This amount reflects Wisconsin Electric's receipt of SSR payments from MISO that are higher than Wisconsin Electric anticipated when it filed its rate request in May 2014, as well as an offset of $26.6 million related to a refund of prior fuel costs and the remainder of the proceeds from the Treasury Grant Wisconsin Electric received in connection with its biomass facility. This $26.6 million is being returned to customers in the form of bill credits.
- An electric rate increase for Wisconsin Electric's Wisconsin retail electric customers of $26.6 million (0.9%) for 2016, related to the expiration of the bill credits provided to customers in 2015.
- A rate decrease of $13.9 million (-0.5%) in 2015 related to a forecasted decrease in fuel costs. Wisconsin Electric will make an annual fuel cost filing, as required, for 2016.
- A rate decrease of $10.7 million (-2.4%) for Wisconsin Electric's natural gas customers in 2015, with no rate adjustment in 2016.
- Rate increases of $17.1 million (2.6%) in 2015 and $21.4 million (3.2%) in 2016 for Wisconsin Gas' natural gas customers.
- An increase of approximately $0.5 million (2.0%) for Wisconsin Electric's Downtown Milwaukee (Valley) steam utility customers for 2015, with no rate adjustment in 2016.

- An increase of $1.2 million (7.3%) for Wisconsin Electric's Milwaukee County steam utility customers for 2015, with no rate adjustment in 2016.

These rate adjustments were effective January 1, 2015. The electric rates reflect an increased allocation to fixed charges from 7.8% to 13.6% of total electric revenue requirements to more closely reflect our cost structure. In addition, the authorized return on equity for Wisconsin Electric and Wisconsin Gas was set at 10.2% and 10.3%, respectively. The PSCW also authorized an increase in Wisconsin Gas' financial common equity component to an average of 49.5% compared to the current 47.5%, while Wisconsin Electric's equity component will remain the same. The PSCW's order also allowed for escrow accounting treatment for SSR revenue from MISO.

In January 2015, certain parties appealed a portion of the PSCW's final decision adopting the Company's specific rate design changes, including new charges for customer owned generation within its service territory. We believe the appeal is without merit.

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 reflected 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 retail 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 Wisconsin Electric rates reflected 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 Wisconsin Gas rates reflected 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, Wisconsin Electric's and Wisconsin Gas' allowed return on equity remained at 10.4% and 10.5%, respectively. The PSCW also approved escrow accounting treatment for the Treasury Grant.

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:

- Authorized Wisconsin Electric to suspend the amortization of $148 million of regulatory costs during 2012, with amortization to begin again in 2013.
- Authorized $148 million of carrying costs and depreciation on previously approved air quality and renewable energy projects, effective January 1, 2012.
- Authorized 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 and 2010 Michigan Rate Cases: 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 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. In November 2010, the mines filed a Claim of Appeal of the October 2010 order with the Michigan Court of Appeals. In May 2014, the Court of Appeals issued its decision affirming the MPSC orders in both the 2010 and 2012 rate cases. In August 2014, the mines filed an Application for Leave to Appeal with the Michigan Supreme Court, which Application was denied on February 3, 2015.

Michigan SSR Proceeding: On February 10, 2015, the MPSC issued an Order and Notice of Hearing related to the ongoing operation of Presque Isle Power Plant (PIPP) and the need for us to receive SSR payments with the return of the mines as our retail customers on February 1, 2015. We are unable to predict the resolution of this matter at this time.

For additional information relating to the SSR payments we are receiving, see Industry Restructuring and Competition below.

Wisconsin Fuel Proceedings

Embedded within Wisconsin Electric's 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.

Other Utility Rate Matters

Electric Transmission Cost Recovery: Wisconsin Electric divested its transmission assets with the formation of ATC in January 2001. We procure transmission service from ATC at FERC approved tariff rates. In connection with the formation of ATC, our transmission costs escalated due to the allocation of costs over ATC's footprint 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 at our weighted-average cost of capital. Our 2008 and 2010 PSCW rate orders discontinued escrow accounting for prospective transmission charges and provided for recovery of those costs as incurred. In our 2013 Wisconsin rate case, the PSCW reauthorized escrow accounting for future transmission costs whereby we defer prospective costs that exceed amounts in rates, and we are allowed to earn a return on the incremental unrecovered transmission costs at the short-term debt rate. As of December 31, 2014, we had $32 million of unrecovered transmission costs related to deferrals subsequent to 2012 that earn a return at the short-term debt rate. In addition, as of December 31, 2014, we had $114 million of unrecovered transmission costs related to deferrals prior to 2008 that earn a return at the weighted-average cost of capital. In our 2015 Wisconsin rate case, the PSCW order reaffirmed our deferral of transmission costs.

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 2005 Wisconsin Act 141 (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 was required to increase its renewable energy percentage at least two percentage points to a level of 4.27% for the years 2010-2014. As of December 31, 2014, 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 in November 2013. Wood waste and wood shavings are used to produce renewable electricity and the plant also supports Domtar's sustainable papermaking operations. The final cost of completing this project was $268.9 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 2014. The funding required by Act 141 for 2015 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.

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 2014 and 2013. 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 2015. 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 Sulfur Dioxide (SO_2), Nitrogen Oxide (NO_x), fine particulates, mercury and greenhouse gases; (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 United States Environmental Protection Agency (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 September 2014, the Consent Decree was amended a third time to update some provisions related to the conversion of VAPP from coal to natural gas. In order to achieve the reductions agreed to in the Consent Decree, over the past 11 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 2008, the EPA issued a more stringent 8-hour ozone standard, and made final attainment designations for this revised standard in 2012. Sheboygan County and the eastern portion of Kenosha County were designated as non-attainment areas. As a result, 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 not be required to obtain emission offsets. So long as eastern Kenosha County remains an ozone non-attainment area, the Pleasant Prairie Power Plant will continue to be subject to more stringent permitting requirements and offset provisions.

In April 2014, the U.S. District Court for the Northern District of California adopted a petition from environmental groups to require the EPA to propose a new ozone standard by 2014, and to finalize the standard by October 2015. On November 25, 2014, the EPA proposed to lower the 8-hour ozone standard from its current level of 75 parts per billion. As part of its proposal, the EPA requested comment on values from 60-70 parts per billion. The impact, if any, of a revised standard will depend on how much it is lowered, but could result in widespread areas of the country not being able to meet the new standard.

Fine Particulate Standard: In 2009, the EPA designated three counties in southeast Wisconsin (Milwaukee, Waukesha and Racine) as not meeting the daily standard for Fine Particulate Matter ($PM_{2.5}$). In April 2012, the EPA proposed to determine that these three counties meet the $PM_{2.5}$ standard, and proposed to suspend the requirement that the state submit a State Implementation Plan (SIP) including reasonably available control technology regulations. In February 2014, the EPA re-proposed this determination, and in April 2014, the EPA took action to redesignate the three counties to attainment. Our generating facilities in the counties are now subject to less stringent construction permitting requirements and emission offset provisions are no longer required for modifications to these facilities. In addition, in December 2012, the EPA issued a revised and more stringent annual $PM_{2.5}$ standard. On December 18, 2014, the EPA determined that all areas of Wisconsin and Michigan's Upper Peninsula meet the revised standard and designated them as attainment areas. Therefore, we do not currently expect the lower standard to impose any additional requirements on our operations.

Sulfur Dioxide Standard: The EPA issued a new 1-Hour SO_2 NAAQS that became effective in August 2010. This standard represents a significant change from the previous SO_2 standard, and NAAQS in general, since attainment designations were to be based primarily on modeling rather than monitoring. Typically, attainment designations are based on monitored data. In May 2014, the EPA issued the proposed Data Requirements Rule that would establish procedures and timelines for implementation of the standard. The proposed rule describes the EPA's plans for allowing the states to use either monitoring or modeling to make designations.

We filed comments on the proposed rule with the EPA in July 2014, and proposed a special reliability exclusion for PIPP that would recognize our request to retire the facility, and would exclude it from further modeling or monitoring requirements and subsequent emission reductions. As proposed, the rule affords state agencies latitude in rule implementation. States would have the option of modeling or monitoring to show attainment (subject to EPA approval for this selection). If the state chooses modeling and the sources in an area do not make reductions by 2017, and as a consequence the area is classified as non-attainment, then they would have to make emission reductions by 2023. Alternatively, if a state opted out of modeling and instead chose monitoring, and subsequently monitored non-attainment, then it would face a 2026 compliance date. A non-attainment designation could have negative impacts for a localized geographic area, including permitting constraints for the subject source and for other new or existing sources in the area.

We believe our fleet (with the exception of PIPP) is well positioned to meet this regulation once it is finalized. If PIPP is still operating in the 2021-2022 timeframe, it will likely need additional SO_2 reductions in order to comply with the standard.

Nitrogen Dioxide Standard: In January 2010, the EPA announced a new hourly Nitrogen Dioxide standard, which became effective in April 2010. In February 2012, all areas of Wisconsin and Michigan were designated as unclassifiable. Until these areas are classified as attainment or non-attainment and any potential rules are adopted, we are unable to predict the impact on the operation of our generation facilities.

Mercury and Other Hazardous Air Pollutants: In December 2011, the EPA issued the final Mercury and Air Toxics Standards (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 planning for the addition of a dry sorbent injection system for further control of mercury and acid gases at the plant to comply with MATS. In April 2013, we received a one year MATS compliance extension through April 16, 2016 from the Michigan Department of Environmental Quality (MDEQ).

In addition, both Wisconsin and Michigan have mercury rules that require a 90% reduction of mercury, and compliance with those rules will no longer be required after the compliance date for MATS.

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 three coal fired boilers at the Milwaukee County Power Plant are subject to this rule. We are currently evaluating compliance options for these boilers.

Cross-State Air Pollution Rule: In August 2011, the EPA issued Cross-State Air Pollution Rule (CSAPR), formerly known as the Clean Air Transport Rule. This rule was proposed 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. We and a number of other parties sought judicial review of the rule. In April 2014, the United States Supreme Court issued a decision largely upholding the rule and remanding it for further proceedings consistent with the Court's order. Briefing on further challenges to the rule allowed by the U.S. Supreme Court decision is ongoing. On October 23, 2014, the U.S. Court of Appeals for the D.C. Circuit issued a decision that cleared the way for the EPA to begin implementing CSAPR on January 1, 2015. We expect that there will be sufficient allowances available for PIPP to meet its obligations to operate and provide stability to the transmission system in the Upper Peninsula of Michigan. We also expect to have excess allowances available to sell from our Wisconsin power plants. In light of these developments, we withdrew our challenge to CSAPR.

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 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. We believe we are well positioned to meet the requirements of the Clean Air Visibility rule based on air quality control system additions that are already in place or planned for our generating facilities.

Climate Change: We continue to take measures to reduce our emissions of Greenhouse Gas (GHG). We support flexible, market-based strategies to curb GHG emissions, including emissions trading, emission offset 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 GHG, 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.
- Converting the fuel source at the VAPP from coal to natural gas, scheduled for completion in 2015.
- Retired coal units 1-4 at PIPP.

Federal, state, regional and international authorities have undertaken efforts to limit GHG emissions. The regulation of GHG emissions continues to be a top priority for the President's administration.

In accordance with instructions from the President, the EPA is pursuing regulation of GHG emissions using its existing authority under the Clean Air Act. In September 2013, the EPA issued new proposed New Source Performance Standards with GHG 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 effectively prohibits new conventional coal-fired power plants.

In addition, the EPA issued proposed guidelines relating to GHG emissions from existing generating units in June 2014, and has announced plans to issue final rules by mid-summer 2015. The EPA also published proposed performance standards for modified and reconstructed generating units. The proposed guidelines for existing fossil generating units seek to attain state-specific GHG rate reductions by 2030, and require states to submit plans as early as June 30, 2016. Single states requesting a one year extension would be required to submit plans by June 30, 2017, and states that are part of a multi-state plan that request a two year extension would be required to submit plans by June 30, 2018. The EPA is seeking GHG rate reductions in Wisconsin of 34% and in Michigan of 31% by 2030, with interim reduction goals beginning in 2020 of 30% and 27% respectively, with interim goal compliance determined by averaging reductions over the ten year period of 2020 to 2029. The proposed program consists of building blocks that include a combination of power plant efficiency improvements, increased reliance on combined cycle gas units, adding new renewable energy resources, and increased demand side management. We are in the process of reviewing the proposed guidelines to determine the potential impacts to our operations, but the guidelines as currently proposed could result in significant additional compliance costs, including capital expenditures, impact how we operate our existing fossil fueled power plants and biomass facility, and could have a material adverse impact on our operating costs.

In June 2014, the U.S. Supreme Court struck down a portion of the EPA's program for permitting GHG emissions under the Prevention of Significant Deterioration (PSD) and Title V programs. The Court held that a facility's GHG emissions alone cannot trigger a requirement to obtain a permit and that the EPA did not have the authority to "tailor" the statutory permitting thresholds. The Court also upheld those portions of the EPA's program that provide for implementation of GHG emissions limits based on the application of BART for facilities already subject to PSD or Title V permitting requirements for other pollutants. We do not expect that this decision will have a material impact on our facilities.

We are required to report our Carbon Dioxide (CO_2) equivalent emissions from our electric generating facilities under the EPA Greenhouse Gases Reporting Program. For 2013, we reported CO_2 equivalent emissions of approximately 21.9 million metric tonnes to the EPA, compared with approximately 18.1 million metric tonnes for 2012. Based upon our preliminary analysis of the data, we estimate that we will report CO_2 equivalent emissions of approximately 23.3 million metric tonnes to the EPA for 2014. 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 equivalent amounts related to the natural gas our gas utility distributes and sells. For 2013, we reported approximately 10.4 million metric tonnes of CO_2 equivalent to the EPA related to our distribution and sale of natural gas, compared with approximately 8.4 million metric tonnes for 2012. Based upon our preliminary analysis of the monitoring data, we estimate that we will report CO_2 emissions of approximately 10.8 million metric tonnes to the EPA for 2014.

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. We received PSCW approval for this project in March 2014. Construction related to the conversion of the first two boilers was completed in November 2014, and the remaining two boilers are scheduled for completion in 2015.

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. The EPA issued a final Phase II rule that became effective on October 14, 2014. The new rule applies to all of our existing generating facilities with cooling water intake structures, except for the Oak Creek expansion units, which were permitted under the Phase I rules.

The new Phase II rule allows facility owners to select from seven options available to meet the impingement mortality (IM) reduction standard. BTA determinations will be made over the next several years by the Wisconsin Department of Natural Resources (WDNR) and MDEQ, subject to EPA oversight, when facility permits are reissued. Based upon our assessment, we believe that the existing technologies at our generating facilities will allow us to demonstrate that, other than VAPP, all of our facilities satisfy the IM BTA standard. During 2015 and 2016, we plan to install fish protection screens at VAPP that will meet the IM BTA standard.

The BTA determinations for entrainment mortality (EM) reduction will be made by the WDNR and MDEQ on a case-by-case basis. The new rule requires state permitting agencies to determine EM BTA on a site-specific basis taking into consideration several factors. We have received an EM BTA determination by the WDNR, with EPA concurrence, for our proposed intake modification at VAPP. We cannot yet determine what, if any, intake structure or operational modifications will be required to meet the new requirements for our other generating facilities.

The WDNR issued a new Wisconsin Pollutant Discharge Elimination System (WPDES) permit for VAPP that became effective on January 1, 2013 that contains several additional 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 a compliance schedule for the installation of the new cooling water intake fish protection screens.

On November 10, 2014, the WDNR reissued the WPDES permit for the Paris Generating Station (PSGS). We believe that the WDNR imposed unreasonable permit conditions with respect to temperature monitoring, the control of water treatment additive and phosphorus discharges.

To address these permit conditions, we filed a petition for a contested case hearing with the WDNR on January 9, 2015. On the same day, we also filed a request to be covered by the statewide phosphorus variance to address one of our concerns with the permit. We are working with the WDNR to determine if a settlement is possible. A decision on the phosphorus variance request is pending.

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 September 2015. 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

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. The EPA issued the final rule on December 22, 2014, under which coal combustion residuals will be regulated as a non-hazardous waste. The rule is self-implementing which means that affected facilities must comply with the rules regardless of whether a state adopts the rule. We have been meeting the state requirements and have plans in place to implement the additional federal rule requirements.

In the preamble to the final rule, the EPA referenced reports it received with respect to the molybdenum concerns raised in southeastern Wisconsin, and indicated it will continue to evaluate the beneficial use of coal ash in unencapsulated construction.

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 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.

On September 9, 2014, a new stray voltage case was filed against Wisconsin Electric in Sheboygan County, Wisconsin. We do not believe this lawsuit has any merit and intend to defend the case vigorously. This lawsuit is not expected to have a material adverse effect on our financial statements.

INDUSTRY RESTRUCTURING AND COMPETITION

Electric Utility Industry

The regulated energy industry continues to experience significant changes. FERC continues to support large Regional Pricing Organizations (RTOs), which affects the structure of the wholesale market. To this end, MISO implemented the MISO Energy Markets, including the use of Locational Marginal Price (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.

Michigan Business

Michigan Settlement: On January 12, 2015, Wisconsin Energy and Wisconsin Electric entered into an agreement with the Governor of the State of Michigan, the Attorney General of the State of Michigan, the Staff of the MPSC, and Tilden Mining Company and Empire Iron Mining Partnership, owners of the two mines in the Upper Peninsula of Michigan, to resolve all objections these parties raised at the FERC and the MPSC related to Wisconsin Energy's proposed acquisition of Integrys. The agreement forms the basis for a settlement agreement between the parties and includes the following provisions which directly impact Wisconsin Energy and Wisconsin Electric:

- The Governor, the Attorney General and the owners of the mines will each file a letter with FERC stating that they do not have any objection to FERC's approval of our acquisition of Integrys, and will refrain from taking any action at FERC seeking to oppose, otherwise condition or delay consummation of the transaction. These letters have been filed with FERC.
- The settlement agreement will request that the MPSC order approving our acquisition of Integrys be subject to the following conditions: (i) the closing of the sale of Wisconsin Electric's Michigan electric distribution assets and PIPP to Upper Peninsula Power Company (UPPCO) contemporaneously with the closing of the acquisition of Integrys; (ii) the closing of the sale of Wisconsin Public Service Corporation's Michigan electric distribution assets to UPPCO contemporaneously with the closing of the acquisition; and (iii) termination of the PIPP SSR agreement between MISO and Wisconsin Electric no later than the closing date of the acquisition. To this end, Wisconsin Electric has entered into a non-binding term sheet to sell these assets to UPPCO, which is described in more detail below. The Attorney General, the MPSC Staff and the owners of the mines will not seek or support any other conditions on granting of MPSC approval of our acquisition of Integrys. Wisconsin Public Service Corporation is a subsidiary of Integrys.

The settlement agreements entered into by these parties, as well as two other intervenors in the MPSC proceedings, were filed with the MPSC on January 30, 2015.

SSR Payments: 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.

In August 2013, the mines, which were served on an interruptible tariff, notified us that they intended to switch to an alternative electric supplier. In September 2013, the switch was made. In addition, other smaller retail customers have switched to an alternative electric supplier. Following that decision, we initiated discussions with MISO to compensate Wisconsin Electric for the continued short-term operation of the plant through 2014.

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.

In January 2014, we entered into an SSR agreement (Suspension) with MISO to recover costs for operating and maintaining the units. The agreement was effective February 1, 2014, had a one year term, and specified monthly payments to Wisconsin Electric of $4.4 million to cover fixed costs. The agreement also provided for the payment of our variable costs to operate and maintain the plant. MISO filed the SSR agreement with FERC, and on April 1, 2014, FERC conditionally accepted the agreement as filed, subject to further review and FERC order. We began receiving SSR payments from MISO in the second quarter of 2014 retroactive to the agreement's effective date of February 1, 2014.

In addition, we issued a request for proposals regarding the potential purchase of PIPP in January 2014. We did not receive any valid proposals by the March 3, 2014 deadline. Based upon our evaluation and the lack of interest to purchase the plant, in April 2014, we filed a request with MISO to retire PIPP effective October 15, 2014. In May 2014, MISO informed us that they had determined the operation of all five units at PIPP was necessary for reliability purposes; therefore, the units would continue to be designated as SSR units.

We entered into a new SSR agreement (Retirement) with MISO, effective October 15, 2014, that covered the operating costs of PIPP through December 2015. The new SSR agreement also included, among other things, costs to comply with the MATS rule and a return on and of our investment in the plant. The new agreement is based on projected costs and is subject to a true-up mechanism. The estimated monthly payments under this agreement are approximately $8.1 million. On November 10, 2014, FERC accepted the new SSR agreement, but it is subject to further action.

MISO is responsible for allocating the SSR costs to various market participants within the MISO footprint consistent with FERC approved tariffs. Several interested parties, including the PSCW and the MPSC, filed complaints with the FERC regarding the allocation among the different jurisdictions of the SSR costs associated with the continued operation of PIPP. On February 19, 2015, FERC acted on the jurisdictional allocation of the SSR costs, reaffirming that it is unjust and unreasonable to allocate SSR costs *pro* rata to all market participants and that SSR costs must be allocated to the load-serving entities that require the operation of SSR units for reliability purposes. FERC directed MISO to file a new study method to identify the entities that benefit from the operation of SSR units within 60 days of the decision date and to allocate the costs directly to these entities.

On February 17, 2015, we entered into an agreement with the owners of the two iron ore mines whereby we agreed to request termination of the SSR agreement effective February 1, 2015, and the two mines agreed to remain full requirements customers until the earlier of the sale of PIPP and July 31, 2015. On the same date, we requested MISO to terminate the SSR agreement, and on February 18, 2015, MISO filed a request with FERC to have the SSR terminated effective February 1, 2015. We do not expect the termination of the SSR agreement to have a material impact on our financial condition or results of operations.

Effective February 1, 2015, the mines returned as retail customers. We expect to defer the net revenue from those sales and will apply these amounts for the benefit of Wisconsin retail electric customers in future rate proceedings. Michigan state law allows the mines to switch to an alternative electric supplier after sufficient notice.

Sale of Michigan Assets: In January 2015, we entered into a non-binding term sheet to sell our Michigan electric distribution assets and PIPP to UPPCO. We currently expect to enter into a definitive agreement by the end of March 2015. The ultimate sale of these assets would have to be approved by several state and federal regulatory bodies, including the MPSC, PSCW and FERC. If the sale is consummated on terms commensurate with the non-binding term sheet, consistent with the treatment that would be applied to a generating unit retirement we will seek recovery of approximately $190 million of net unrecovered plant costs.

We believe that the sale of these assets is in the best interest of our customers because of the costs associated with the next best solution, which includes operating PIPP for at least five more years. These costs would include ongoing operating costs, decommissioning and dismantling costs and any increased costs for additional transmission capacity in the Upper Peninsula.

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, 2014 through May 31, 2015. 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 during 2014 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 a 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

***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. 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; however, in January 2013, the WDNR indicated that it considered this maintenance to be a modification requiring a construction permit. This matter has since been settled. In December 2013, Act 91 was signed into law in Wisconsin, creating a process by which the EPA and WDNR were able to revise the regulations and emissions rates applicable to Units 1 and 4, allowing those units to restart. We received an “after the fact” permit from the WDNR, and the Units are now available for service. On October 24, 2014, the Sierra Club filed for a contested case hearing with the WDNR challenging this permit.

In February 2013, the Sierra Club filed for a contested case hearing with the WDNR in connection with the administration order issued in this matter, which was granted. However, a hearing has not yet been scheduled.

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 Treasury Grant related to the construction of our biomass facility, which was placed into service in November 2013. In December 2013, we recognized income related to the Treasury Grant and we deferred as a regulatory liability the grant proceeds that would be returned to customers subsequent to December 31, 2013. In connection with our Wisconsin retail electric rates that became effective January 1, 2013, our Wisconsin retail electric customers began receiving bill credits for the expected grant proceeds plus the related tax benefits.

In June 2014, we received approximately $76.2 million related to the Treasury Grant. The PSCW approved escrow accounting for the Treasury Grant and the proceeds we received that exceeded the amounts originally included in rates are being returned to customers in the form of bill credits.

As noted above, our Wisconsin retail electric customers are currently receiving bill credits related to the Treasury Grant plus related tax benefits. During 2014, we recognized Treasury Grant income to match the bill credits related to the grant that our Wisconsin retail electric customers received.

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, 2014, we had $1,271.2 million in regulatory assets and $830.6 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, mortality 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	$ 5.5
0.5% decrease in expected rate of return on plan assets	$ 6.8

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 age and other demographics, 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, mortality 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	$	0.6
0.5% decrease in health care cost trend rate in all future years	$	(3.0)
0.5% decrease in expected rate of return on plan assets	$	1.6

In October 2014, the Society of Actuaries released a new set of mortality tables (RP-2014) and an accompanying mortality improvement scale (MP-2014), which incorporates increasing life expectancy experience in the United States. Based on our initial review of the proposed tables, we believe our pension and OPEB obligations would increase by approximately 6% if we adopted these tables. We will continue to evaluate the mortality assumptions in the future, as necessary, to conform to our experience.

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 2014 of approximately $4.9 billion included accrued utility revenues of $291.3 million as of December 31, 2014.

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 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.

WISCONSIN ENERGY CORPORATION
CONSOLIDATED INCOME STATEMENTS
Year Ended December 31

	2014	2013	2012
	(Millions of Dollars, Except Per Share Amounts)		
Operating Revenues	$ 4,997.1	$ 4,519.0	$ 4,246.4
Operating Expenses			
Fuel and purchased power	1,223.3	1,153.0	1,098.6
Cost of gas sold	1,036.1	674.1	545.8
Other operation and maintenance	1,112.4	1,155.0	1,116.1
Depreciation and amortization	408.8	388.1	364.2
Property and revenue taxes	121.8	116.7	121.4
Total Operating Expenses	3,902.4	3,486.9	3,246.1
Treasury Grant	17.4	48.0	—
Operating Income	1,112.1	1,080.1	1,000.3
Equity in Earnings of Transmission Affiliate	66.0	68.5	65.7
Other Income and Deductions, net	13.4	18.8	34.8
Interest Expense, net	241.5	252.1	248.2
Income Before Income Taxes	950.0	915.3	852.6
Income Tax Expense	361.7	337.9	306.3
Net Income	$ 588.3	$ 577.4	$ 546.3
Earnings Per Share			
Basic	$ 2.61	$ 2.54	$ 2.37
Diluted	$ 2.59	$ 2.51	$ 2.35
Weighted Average Common Shares Outstanding (Millions)			
Basic	225.6	227.6	230.2
Diluted	227.5	229.7	232.8

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

WISCONSIN ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS

December 31

ASSETS

	2014	2013
	(Millions of Dollars)	
Property, Plant and Equipment		
In service	$ 15,509.0	$ 14,966.3
Accumulated depreciation	(4,485.1)	(4,257.1)
	11,023.9	10,709.2
Construction work in progress	191.8	149.6
Leased facilities, net	42.0	47.8
Net Property, Plant and Equipment	11,257.7	10,906.6
Investments		
Equity investment in transmission affiliate	424.1	402.7
Other	32.8	36.1
Total Investments	456.9	438.8
Current Assets		
Cash and cash equivalents	61.9	26.0
Accounts receivable, net of allowance for doubtful accounts of $74.5 and $61.0	352.1	406.0
Accrued revenues	291.3	321.1
Materials, supplies and inventories	400.6	329.4
Current deferred tax asset, net	242.7	310.0
Prepayments	148.2	145.7
Other	38.6	12.9
Total Current Assets	1,535.4	1,551.1
Deferred Charges and Other Assets		
Regulatory assets	1,271.2	1,108.5
Goodwill	441.9	441.9
Other	200.3	322.5
Total Deferred Charges and Other Assets	1,913.4	1,872.9
Total Assets	$ 15,163.4	$ 14,769.4

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

	2014	2013
	(Millions of Dollars)	
Capitalization		
Common equity	$ 4,419.7	$ 4,233.0
Preferred stock of subsidiary	30.4	30.4
Long-term debt	4,186.4	4,363.2
Total Capitalization	8,636.5	8,626.6
Current Liabilities		
Long-term debt due currently	424.1	342.2
Short-term debt	617.6	537.4
Accounts payable	363.3	342.6
Accrued payroll and benefits	95.1	96.9
Other	168.6	177.3
Total Current Liabilities	1,668.7	1,496.4
Deferred Credits and Other Liabilities		
Regulatory liabilities	830.6	879.1
Deferred income taxes - long-term	2,906.7	2,634.0
Deferred revenue, net	614.1	664.2
Pension and other benefit obligations	203.8	173.2
Other long-term liabilities	303.0	295.9
Total Deferred Credits and Other Liabilities	4,858.2	4,646.4
Commitments and Contingencies (Note Q)		
Total Capitalization and Liabilities	$ 15,163.4	$ 14,769.4

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

	2014	2013	2012
		(Millions of Dollars)	
Operating Activities			
Net income	$ 588.3	$ 577.4	$ 546.3
Reconciliation to cash			
Depreciation and amortization	419.4	400.2	371.7
Deferred income taxes and investment tax credits, net	328.1	312.7	293.2
Contributions to qualified benefit plans	—	—	(100.0)
Change in - Accounts receivable and accrued revenues	80.7	(162.9)	38.3
Inventories	(71.2)	31.3	21.3
Other current assets	(13.9)	2.8	12.1
Accounts payable	23.7	(14.8)	43.8
Accrued income taxes, net	(11.4)	36.6	116.9
Deferred costs, net	(15.1)	(8.7)	9.2
Other current liabilities	(18.8)	7.2	(14.9)
Other, net	(112.1)	49.2	(164.0)
Cash Provided by Operating Activities	1,197.7	1,231.0	1,173.9
Investing Activities			
Capital expenditures	(736.1)	(687.4)	(707.0)
Investment in transmission affiliate	(13.1)	(10.5)	(15.7)
Proceeds from asset sales	13.9	2.5	8.7
Change in restricted cash	—	2.7	42.8
Cost of removal, net of salvage	(25.1)	(37.8)	(38.3)
Other, net	3.6	(15.3)	(20.1)
Cash Used in Investing Activities	(756.8)	(745.8)	(729.6)
Financing Activities			
Exercise of stock options	50.3	48.5	49.8
Purchase of common stock	(123.2)	(223.4)	(153.2)
Dividends paid on common stock	(352.0)	(328.9)	(276.3)
Issuance of long-term debt	250.0	251.0	251.8
Retirement of long-term debt	(324.3)	(397.2)	(20.3)
Change in short-term debt	80.2	142.8	(275.3)
Other, net	14.0	12.4	0.7
Cash Used in Financing Activities	(405.0)	(494.8)	(422.8)
Change in Cash and Cash Equivalents	35.9	(9.6)	21.5
Cash and Cash Equivalents at Beginning of Year	26.0	35.6	14.1
Cash and Cash Equivalents at End of Year	$ 61.9	$ 26.0	$ 35.6

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, 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
Net income			588.3	588.3
Common stock cash dividends of $1.56 per share			(352.0)	(352.0)
Exercise of stock options		50.3		50.3
Purchase of common stock		(123.2)		(123.2)
Tax benefit from share based compensation		16.8		16.8
Stock-based compensation and other		6.5		6.5
Balance - December 31, 2014	$ 2.3	$ 300.1	$ 4,117.3	$ 4,419.7

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

WISCONSIN ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CAPITALIZATION

December 31

		2014	2013
		(Millions of Dollars)	
Common Equity (see accompanying statement)		$ 4,419.7	$ 4,233.0
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)	6.00% due 2014	—	300.0
	6.25% due 2015	250.0	250.0
	1.70% due 2018	250.0	250.0
	4.25% due 2019	250.0	250.0
	2.95% due 2021	300.0	300.0
	6-1/2% due 2028	150.0	150.0
	5.625% due 2033	335.0	335.0
	5.70% due 2036	300.0	300.0
	3.65% due 2042	250.0	250.0
	4.25% due 2044	250.0	—
	6-7/8% due 2095	100.0	100.0
Wisconsin Gas Debentures (unsecured)	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 2014-2030 (a)	117.2	122.1
	5.209% due 2014-2030 (b)	223.9	231.5
	4.673% due 2014-2031 (b)	184.7	190.9
	6.00% due 2014-2033 (a)	134.6	138.4
	6.09% due 2030-2040 (b)	275.0	275.0
	5.848% due 2031-2041 (b)	215.0	215.0
WECC Notes (unsecured)	6.94% due 2028	50.0	50.0
Other Notes (secured, nonrecourse)	6.00% due 2021	—	1.8
	4.81% effective rate due 2030	2.0	2.0
Obligations under capital leases		84.5	104.3
Unamortized discount, net and other		(26.4)	(25.6)
Long-term debt and capital lease obligations due currently		(424.1)	(342.2)
Total Long-Term Debt		4,186.4	4,363.2
Total Long-Term Capitalization		$ 8,636.5	$ 8,626.6

(a) Senior notes are secured by a collateral assignment of the leases between PWGS and Wisconsin Electric related to PWGS 1 and 2.

(b) 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.

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.

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	2014	2013	2012
	(Millions of Dollars)		
AFUDC - Equity	$ 5.6	$ 18.3	$ 35.3
Gain on Property Sales	7.5	0.8	2.7
Other, net	0.3	(0.3)	(3.2)
Total Other Income and Deductions, net	$ 13.4	$ 18.8	$ 34.8

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	2014	2013
	(Millions of Dollars)	
Utility Energy	$ 12,290.7	$ 11,779.8
Non-Utility Energy	3,127.8	3,091.3
Other	90.5	95.2
Total	$ 15,509.0	$ 14,966.3

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 2014, 2013 and 2012.

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 $741.1 million as of December 31, 2014 and $724.5 million as of December 31, 2013.

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

CWIP	2014	2013
	(Millions of Dollars)	
Utility Energy	$ 170.1	$ 132.7
Non-Utility Energy	21.1	16.5
Other	0.6	0.4
Total	$ 191.8	$ 149.6

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

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

	2014	2013	2012
		(Millions of Dollars)	
AFUDC - Debt	$ 2.3	$ 7.7	$ 14.7
AFUDC - Equity	$ 5.6	$ 18.3	$ 35.3

Deferred Revenue: 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 2014, 2013 and 2012 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	2014	2013
	(Millions of Dollars)	
Fossil Fuel	$ 125.6	$ 117.7
Materials and Supplies	150.2	133.9
Natural Gas in Storage	124.8	77.8
Total	$ 400.6	$ 329.4

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, 2014 and 2013, 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 2014 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, 2014, 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, 2014 and 2013. 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:

	2014	2013	2012
Risk-free interest rate	0.1% - 3.0%	0.1% - 1.9%	0.1% - 2.0%
Dividend yield	3.8%	3.7%	3.9%
Expected volatility	18.0%	18.0%	19.0%
Expected life (years)	5.8	5.9	5.9
Expected forfeiture rate	2.0%	2.0%	2.0%
Weighted-average fair value of our stock options granted	$4.18	$3.45	$3.34

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 2014. For the years ended December 31, 2014 and December 31, 2013, $17.4 million and $48.0 million, respectively, was recognized as income, which reflects the amount that was returned to customers in the form of bill credits during the year. The accounting reflects the regulatory treatment of the grant.

In June 2014, we received approximately $76.2 million related to the Treasury Grant. The PSCW approved escrow accounting for the Treasury Grant and the proceeds we received that exceeded the amounts originally included in rates are being returned to customers in the form of bill credits.

B -- RECENT ACCOUNTING PRONOUNCEMENTS

Revenue Recognition: In May 2014, the Financial Accounting Standards Board and the International Accounting Standards Board issued their joint revenue recognition standard, Accounting Standards Update 2014-09, Revenue from Contracts with Customers. This guidance is effective for fiscal years and interim periods beginning after December 15, 2016, and can either be applied retrospectively or as a cumulative-effect adjustment as of the date of adoption. We are currently assessing the effects this guidance may have on our consolidated financial statements.

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, 2014, we had $12.8 million of regulatory assets not earning a return and $115.1 million of regulatory assets earning a return based on short-term interest rates.

In December 2014, the PSCW issued a rate order effective January 1, 2015 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:

	2014	2013
	(Millions of Dollars)	
Regulatory Assets		
Deferred unrecognized pension costs	$ 629.5	$ 537.6
Deferred income tax related	176.0	169.5
Escrowed electric transmission costs	146.0	126.8
Escrowed PTF	66.6	49.3
Escrowed conservation	58.0	66.9
Deferred plant related -- capital lease	42.3	56.5
Deferred environmental costs	45.9	47.0
Other, net	106.9	54.9
Total regulatory assets	$ 1,271.2	$ 1,108.5
Regulatory Liabilities		
Deferred cost of removal obligations	$ 741.1	$ 724.5
Escrowed bad debt costs	30.1	64.6
Other, net	59.4	90.0
Total regulatory liabilities	$ 830.6	$ 879.1

D -- PROPOSED ACQUISITION

On June 22, 2014, Wisconsin Energy and Integrys entered into an agreement and plan of merger (Merger Agreement) under which Wisconsin Energy will acquire Integrys. Integrys' shareholders will receive 1.128 shares of Wisconsin Energy common stock and $18.58 in cash per Integrys share of common stock. We expect to finance the acquisition through the issuance of approximately 91 million shares of Wisconsin Energy common stock to Integrys shareholders and through the issuance of approximately $1.5 billion of debt. We will also assume all of Integrys' outstanding debt. The combined company will be named WEC Energy Group, Inc.

The acquisition is subject to several conditions, including, among others, approval of the shareholders of both Wisconsin Energy and Integrys, the expiration or termination of the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 (HSR Act), and the receipt of approvals from various government agencies, including FERC, Federal Communications Commission, PSCW, Illinois Commerce Commission, MPSC and Minnesota Public Utilities Commission. The status of these matters as of December 31, 2014 is as follows:

- On August 6, 2014, we filed applications for approval with the PSCW, Illinois Commerce Commission, MPSC and Minnesota Public Utilities Commission.
- On August 15, 2014, we filed an application with the FERC. The initial public comment period closed on October 17, 2014. We subsequently submitted additional information to respond to FERC questions on December 18, 2014. That comment period is now closed.
- On September 24, 2014, we submitted our HSR Act filings, and on October 24, 2014, the United States Department of Justice closed its review of the transaction with no further action required. In addition, on October 24, 2014, the Federal Trade Commission granted early termination of the 30-day waiting period required by the HSR Act.
- On November 21, 2014, the shareholders of Wisconsin Energy voted to approve the issuance of common stock as contemplated by the Merger Agreement, as well as to amend the restated articles of incorporation to change the name of Wisconsin Energy from Wisconsin Energy Corporation to WEC Energy Group, Inc. The shareholders of Integrys approved the adoption of the Merger Agreement at its shareholder meeting held on November 21, 2014.

We anticipate the transaction closing in the second half of 2015.

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 2014 and 2013:

	2014	2013
	(Millions of Dollars)	
Balance as of January 1	$ 42.3	$ 44.3
Liabilities Settled	(1.1)	(4.4)
Accretion	2.4	2.4
Balance as of December 31	$ 43.6	$ 42.3

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 eight 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 $174.0 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 2014, 2013 and 2012 were $53.0 million, $50.3 million and $45.8 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	2014	2013	2012
		(Millions of Dollars)	
Current tax expense	$ 33.6	$ 25.2	$ 13.1
Deferred income taxes, net	329.2	313.8	294.4
Investment tax credit, net	(1.1)	(1.1)	(1.2)
Total Income Tax Expense	$ 361.7	$ 337.9	$ 306.3

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

	2014		2013		2012	
Income Tax Expense	Amount	Effective Tax Rate	Amount	Effective Tax Rate	Amount	Effective Tax Rate
			(Millions of Dollars)			
Expected tax at statutory federal tax rates	$ 332.5	35.0 %	$ 320.3	35.0 %	$ 298.4	35.0 %
State income taxes net of federal tax benefit	50.5	5.3 %	49.0	5.3 %	43.3	5.1 %
Production tax credits	(17.4)	(1.8)%	(16.7)	(1.8)%	(15.9)	(1.9)%
Treasury Grant	(3.8)	(0.4)%	(7.4)	(0.8)%	—	— %
AFUDC - Equity	(1.9)	(0.2)%	(6.4)	(0.7)%	(12.3)	(1.4)%
Investment tax credit restored	(1.1)	(0.1)%	(1.1)	(0.1)%	(1.2)	(0.1)%
Domestic production activities deduction	—	— %	—	— %	(12.6)	(1.5)%
Other, net	2.9	0.3 %	0.2	— %	6.6	0.7 %
Total Income Tax Expense	$ 361.7	38.1 %	$ 337.9	36.9 %	$ 306.3	35.9 %

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

Deferred Tax Assets	2014	2013
	(Millions of Dollars)	
Current		
Future federal tax benefits	$ 221.7	$ 309.7
Employee benefits and compensation	13.7	13.8
Other	47.7	56.0
Total Current Deferred Tax Assets	283.1	379.5
Non-current		
Deferred revenues	221.3	237.0
Employee benefits and compensation	98.2	95.6
Future federal tax benefits	—	32.5
Property-related	28.8	28.2
Construction advances	18.9	18.3
Other	51.8	62.9
Total Non-Current Deferred Tax Assets	419.0	474.5
Total Deferred Tax Assets	$ 702.1	$ 854.0

Deferred Tax Liabilities	2014	2013
	(Millions of Dollars)	
Current		
Prepaid items	$ 40.4	$ 69.5
Total Current Deferred Tax Liabilities	40.4	69.5
Non-current		
Property-related	2,750.4	2,574.4
Employee benefits and compensation	242.5	238.5
Investment in transmission affiliate	188.6	169.9
Deferred transmission costs	58.5	50.8
Other	85.7	74.9
Total Non-current Deferred Tax Liabilities	3,325.7	3,108.5
Total Deferred Tax Liabilities	$ 3,366.1	$ 3,178.0

Consolidated Balance Sheet Presentation	2014	2013
Current Deferred Tax Asset	$ 242.7	$ 310.0
Non-Current Deferred Tax Liability	$ 2,906.7	$ 2,634.0

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

As of December 31, 2014, we had approximately $416.2 million and $76.0 million of net operating loss and tax credit carryforwards resulting in deferred tax assets of $145.7 million and $76.0 million, respectively. As of December 31, 2013, we had approximately $810.3 million and $58.6 million of net operating loss and tax credit carryforwards resulting in deferred tax assets of $283.6 million and $58.6 million, respectively. The tax credit and net operating loss carryforwards begin to expire in 2029. We anticipate that we will have future taxable income sufficient to utilize these deferred tax assets.

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

	2014	2013
	(Millions of Dollars)	
Balance as of January 1	$ 8.4	$ 11.3
Reductions for tax positions of prior years	(1.2)	(2.9)
Balance as of December 31	$ 7.2	$ 8.4

The amount of unrecognized tax benefits as of December 31, 2014 and 2013 excludes deferred tax assets related to uncertainty in income taxes of $7.2 million and $8.4 million, respectively. As of December 31, 2014 and 2013, there were no unrecognized tax benefits that, if recognized, would impact the effective tax rate for continuing operations.

We recognize interest and penalties accrued related to unrecognized tax benefits as a component of income tax expense. For the years ended December 31, 2014, 2013 and 2012, we recognized approximately $0.3 million, $0.2 million and $0.2 million, respectively, of accrued interest in the Consolidated Income Statements. For the years ended December 31, 2014, 2013 and 2012, we recognized no penalties in the Consolidated Income Statements. We had approximately $0.7 million and $0.4 million of interest accrued and no penalties accrued on the Consolidated Balance Sheets as of December 31, 2014 and 2013, respectively.

We do not anticipate any significant increases or decreases in the total amounts of unrecognized tax benefits within the next 12 months.

Our primary tax jurisdictions include the United States and the state of Wisconsin. Currently, the tax years of 2011 through 2014 are subject to Federal examination, and the tax years 2010 through 2014 are subject to examination by the state of Wisconsin.

H -- COMMON EQUITY

As of December 31, 2014 and 2013, we had 325,000,000 shares of common stock, one cent par value, authorized under our charter, of which 225,517,339 and 225,962,959 common shares, respectively, were outstanding. All share-based compensation is currently fulfilled by purchases on the open market by our independent agents and do not dilute shareholders' ownership.

Acquisition of Integrys: On June 22, 2014, we entered into an agreement to acquire Integrys. Integrys shareholders will receive 1.128 shares of Wisconsin Energy common stock and $18.58 in cash per share of Integrys common stock. The proposed acquisition is scheduled to close in the second half of 2015. We expect to finance the acquisition through the issuance of approximately $1.5 billion of debt and approximately 91 million shares of Wisconsin Energy common stock.

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

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

	2014	2013	2012
	(Millions of Dollars)		
Performance units	$ 15.4	$ 12.7	$ 16.3
Stock options	3.7	3.9	2.7
Restricted stock	2.8	2.4	3.0
Share-based compensation expense	$ 21.9	$ 19.0	$ 22.0
Related Tax Benefit	$ 8.8	$ 7.6	$ 8.8

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

We expect that substantially all of the outstanding options as of December 31, 2014 will be exercised.

The following is a summary of our stock option activity during 2014:

Stock Options	Number of Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (Millions)
Outstanding as of January 1, 2014	8,089,710	$ 26.84		
Granted	899,500	$ 41.03		
Exercised	(2,201,821)	$ 22.85		
Forfeited	(17,195)	$ 37.42		
Outstanding as of December 31, 2014	6,770,194	$ 29.99	5.7	$ 154.0
Exercisable as of December 31, 2014	3,890,339	$ 24.10	3.9	$ 111.4

In January 2015, the Compensation Committee of the Board of Directors (Compensation Committee) awarded 516,475 non-qualified stock options with an exercise price of $52.895 to our officers and other key employees under its normal schedule of awarding long-term incentive compensation.

The intrinsic value of options exercised during the years ended December 31, 2014, 2013 and 2012 was $50.5 million, $44.5 million and $47.5 million, respectively. Cash received from options exercised during the years ended December 31, 2014, 2013 and 2012 was $50.3 million, $48.5 million and $49.8 million, respectively. The actual tax benefit realized for the tax deductions from option exercises for the same periods was approximately $19.9 million, $17.8 million and zero, respectively.

The following table summarizes information about stock options outstanding as of December 31, 2014:

	Options Outstanding			Options Exercisable		
		Weighted-Average			Weighted-Average	
Range of Exercise Prices	Number of Options	Exercise Price	Remaining Contractual Life (Years)	Number of Options	Exercise Price	Remaining Contractual Life (Years)
$17.10 to $21.11	1,498,071	$ 20.86	3.5	1,498,071	$ 20.86	3.5
$23.88 to $29.35	2,153,513	$ 25.06	3.7	2,153,513	$ 25.06	3.7
$34.88 to $41.03	3,118,610	$ 37.79	8.0	238,755	$ 35.88	7.4
	6,770,194	$ 29.99	5.7	3,890,339	$ 24.10	3.9

The following table summarizes information about our non-vested options during 2014:

Non-Vested Stock Options	Number of Options	Weighted-Average Fair Value
Non-Vested as of January 1, 2014	2,380,790	$ 3.38
Granted	899,500	$ 4.18
Vested	(383,240)	$ 3.26
Forfeited	(17,195)	$ 3.56
Non-Vested as of December 31, 2014	2,879,855	$ 3.65

As of December 31, 2014, total compensation costs related to non-vested stock options not yet recognized was approximately $2.1 million, which is expected to be recognized over the next 19 months on a weighted-average basis.

Restricted Shares: The Compensation Committee has also approved restricted stock grants to certain key employees and directors. The following restricted stock activity occurred during 2014:

Restricted Shares	Number of Shares	Weighted-Average Market Price
Outstanding as of January 1, 2014	150,698	
Granted	71,504	$ 40.96
Released	(63,509)	$ 33.02
Forfeited	(3,214)	$ 38.47
Outstanding as of December 31, 2014	155,479	

In January 2015, the Compensation Committee awarded 60,164 restricted shares to our directors, officers and other key employees under its normal schedule of awarding long-term incentive compensation. These awards have a three-year vesting period, and generally, one-third of the award vests on each anniversary of the grant date. During the vesting period, restricted share recipients also have voting rights and are entitled to dividends in the same manner as other shareholders.

We record the market value of the restricted stock awards on the date of grant and then we charge their value to expense over the vesting period of the awards. The intrinsic value of restricted stock vesting was $2.7 million, $4.0 million and $3.5 million for the years ended December 31, 2014, 2013, and 2012, respectively. The actual tax benefit realized for the tax deductions from released restricted shares for the same years was $1.0 million, $1.3 million and zero, respectively.

As of December 31, 2014, total compensation cost related to restricted stock not yet recognized was approximately $2.8 million, which is expected to be recognized over the next 20 months on a weighted-average basis.

Performance Units: In January 2014, 2013 and 2012, the Compensation Committee awarded 233,735, 239,120 and 346,570 performance units, respectively, to officers and other key employees under the Wisconsin Energy Performance Unit Plan. Under the grants, the ultimate number of units that will be awarded is dependent upon the achievement of certain financial performance of our stock over a three-year period. Under the terms of the award, participants may earn between 0% and 175% of the base performance unit award. All grants are settled in cash. We are accruing compensation costs over the three-year performance period based on our estimate of the final expected value of the awards. Performance units earned as of December 31, 2014, 2013 and 2012 vested and were settled during the first quarter of 2015, 2014 and 2013, and had a total intrinsic value of $13.2 million, $14.8 million and $19.3 million, respectively. The actual tax benefit realized for the tax deductions from the distribution of performance units was approximately $4.8 million, $5.3 million and $7.0 million, respectively.

In January 2015, the Compensation Committee awarded 195,365 performance units to our officers and other key employees under its normal schedule of awarding long-term incentive compensation.

As of December 31, 2014, total compensation cost related to performance units not yet recognized was approximately $12.6 million, which is expected to be recognized over the next 20 months on a weighted-average basis.

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

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

Wisconsin Electric and Wisconsin Gas are required to maintain capital structures that differ from GAAP as they reflect regulatory adjustments. The 2013 PSCW rate case order required Wisconsin Electric to maintain a common equity ratio range of between 48.5% and 53.5%, and Wisconsin Gas to maintain a capital structure which had a common equity range of between 45.0% and 50.0%. The 2015 PSCW rate case requires Wisconsin Electric to maintain a common equity ratio range of between 48.5% and 53.5%, and Wisconsin Gas to maintain a capital structure which has a common equity range of between 47.0% and 52.0%. Each company is in compliance with its respective common equity range as outlined within the 2013 PSCW rate case. Wisconsin Electric and Wisconsin Gas must obtain PSCW approval if they pay dividends above the test year levels that would cause either company to fall below the authorized levels of common equity.

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

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

As of December 31, 2014, the restricted net assets of consolidated and unconsolidated subsidiaries and our equity in undistributed earnings of 50% or less owned investees accounted for by the equity method total approximately $3.7 billion. This amount exceeds 25% of our consolidated net assets as of December 31, 2014.

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

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

Share Repurchase Program: We do not expect to issue new shares under our various employee benefit plans and our dividend reinvestment and share purchase plan; rather, we instruct independent plan agents to purchase the shares in the open market. In that regard, no new shares of common stock were issued in 2014, 2013 or 2012.

In December 2013, our Board of Directors authorized a share repurchase program for the purchase of up to $300.0 million of our common stock through open market purchases or privately negotiated transactions from January 1, 2014 through the end of 2017. On June 22, 2014, in connection with the proposed acquisition of Integrys, the Board of Directors terminated this share repurchase program. For the twelve months ended December 31, 2014, we repurchased $18.6 million of our common stock pursuant to the terminated program at an average cost of $43.66 per share. All of these shares were purchased during the first quarter of 2014. A previous share repurchase program authorized by our Board of Directors expired at the end of 2013. In addition, we have instructed our independent agents to purchase shares on the open market to fulfill exercised stock options and restricted stock awards. The following table identifies the shares purchased by the Company for the year ending December 31:

	2014		2013		2012	
	Shares	Cost	Shares	Cost	Shares	Cost
	(In Millions)					
Under share repurchase programs	0.4	$ 18.6	3.0	$ 126.0	1.5	$ 51.8
To fulfill exercised stock options and restricted stock awards	2.3	104.6	2.4	97.4	2.8	101.4
Total	2.7	$ 123.2	5.4	$ 223.4	4.3	$ 153.2

I -- PREFERRED STOCK

The following table shows preferred stock authorized and outstanding at December 31, 2014 and 2013:

	Shares Authorized	Shares Outstanding	Redemption Price Per Share	Total
				(In Millions)
Wisconsin Energy				
$.01 par value Preferred Stock	15,000,000	—	—	$ —
Wisconsin Electric				
$100 par value, Six Per Cent. Preferred Stock	45,000	44,498	—	$ 4.4
$100 par value, Serial Preferred Stock	2,286,500			
3.60% Series		260,000	$ 101	26.0
$25 par value, Serial Preferred Stock	5,000,000	—	—	—
Total preferred stock of subsidiary				$ 30.4

J -- LONG-TERM DEBT AND CAPITAL LEASE OBLIGATIONS

Debentures and Notes: As of December 31, 2014, the maturities and sinking fund requirements of our long-term debt outstanding (excluding obligations under capital leases) were as follows:

	(Millions of Dollars)
2015	$ 399.5
2016	27.4
2017	29.5
2018	281.1
2019	282.7
Thereafter	3,532.2
Total	$ 4,552.4

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

Wisconsin Electric is the obligor under two series of tax-exempt pollution control refunding bonds in outstanding principal amount of $147 million. In August 2009, Wisconsin Electric terminated letters of credit that provided credit and liquidity support for the bonds, which resulted in a mandatory tender of the bonds. Wisconsin Electric purchased the bonds at par plus accrued interest to the date of purchase. As of December 31, 2014 and 2013, the repurchased bonds were still outstanding, but were not reported in our consolidated long-term debt or included on our Consolidated Statements of Capitalization because they are held by Wisconsin Electric. Depending on market conditions and other factors, Wisconsin Electric may change the method used to determine the interest rate on the bonds and have them remarketed to third parties.

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

Effective May 2017, the $500 million of Junior Notes will bear interest at the three-month LIBOR Rate plus 211.25 basis points and will reset quarterly.

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

We treat the long-term power purchase contract as an operating lease for rate-making purposes and we record our minimum lease payments as purchased power expense on the Consolidated Income Statements. We paid a total of $34.9 million and $33.7 million in lease payments during 2014 and 2013, respectively. We record the difference between the minimum lease payments and the sum of imputed interest and amortization costs calculated under capital lease accounting as a deferred regulatory asset on our Consolidated Balance Sheets (see Regulatory Assets - Deferred plant related -- capital lease in Note C). Due to the timing and the amounts of the minimum lease payments, the regulatory asset increased to approximately $78.5 million during 2009, at which time the regulatory asset began to be reduced to zero over the remaining life of the contract. The total obligation under the capital lease was $84.5 million as of December 31, 2014, and will decrease to zero over the remaining life of the contract.

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

Capital Lease Assets	2014	2013
	(Millions of Dollars)	
Leased Facilities		
Long-term power purchase commitment	$ 140.3	$ 140.3
Accumulated amortization	(98.3)	(92.5)
Total Leased Facilities	$ 42.0	$ 47.8

Future minimum lease payments under our capital lease and the present value of our net minimum lease payments as of December 31, 2014 are as follows:

	(Millions of Dollars)
2015	$ 43.5
2016	45.1
2017	13.9
2018	14.7
2019	15.5
Thereafter	41.3
Total Minimum Lease Payments	174.0
Less: Estimated Executory Costs	(54.7)
Net Minimum Lease Payments	119.3
Less: Interest	(34.8)
Present Value of Net Minimum Lease Payments	84.5
Less: Due Currently	(24.6)
	$ 59.9

K -- SHORT-TERM DEBT

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

Short-Term Debt	2014 Balance	2014 Interest Rate	2013 Balance	2013 Interest Rate
	(Millions of Dollars, except for percentages)			
Commercial paper	$ 617.6	0.22%	$ 537.4	0.20%

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

	2014	2013
	(Millions of Dollars, except for percentages)	
Maximum Short-Term Debt Outstanding	$ 721.4	$ 594.5
Average Short-Term Debt Outstanding	$ 468.1	$ 359.1
Weighted-Average Interest Rate	0.18%	0.25%

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

As of December 31, 2014, we had approximately $1.2 billion of available undrawn lines under our bank back-up credit facilities and $617.6 million of commercial paper outstanding that was supported by the available lines of credit. In December 2014, we amended each of our credit facilities to extend their expirations from December 2017 to December 2019.

The Wisconsin Energy, Wisconsin Electric and Wisconsin Gas bank back-up credit facilities contain customary covenants, including certain limitations on the respective companies' ability to sell assets. The credit facilities also contain customary events of default, including payment defaults, material inaccuracy of representations and warranties, covenant defaults, bankruptcy proceedings, certain judgments, Employee Retirement Income Security Act of 1974 defaults and change of control. In addition, pursuant to the terms of Wisconsin Energy's credit agreement, Wisconsin Energy must ensure that certain of its subsidiaries comply with several of the covenants contained therein.

As of December 31, 2014, we were in compliance with all financial covenants.

L -- DERIVATIVE INSTRUMENTS

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

We record derivative instruments on the balance sheet as an asset or liability measured at its fair value, and changes in the derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are met or we receive regulatory treatment for the derivative. For most energy related physical and financial contracts in our regulated operations that qualify as derivatives, the PSCW allows the effects of the fair market value accounting to be offset to regulatory assets and liabilities. As of December 31, 2014, we recognized $14.7 million in regulatory assets and $14.2 million in regulatory liabilities related to derivatives in comparison to $0.3 million in regulatory assets and $9.6 million in regulatory liabilities as of December 31, 2013.

We record our current derivative assets on the balance sheet in other current assets and the current portion of the liabilities in other current liabilities. The long-term portion of our derivative assets of $0.6 million is recorded in other deferred charges and other assets, and the long-term portion of our derivative liabilities of $0.8 million is recorded in other deferred credit and other liabilities. Our Consolidated Balance Sheets as of December 31, 2014 and 2013 include:

	December 31, 2014		December 31, 2013	
	Derivative Asset	Derivative Liability	Derivative Asset	Derivative Liability
	(Millions of Dollars)			
Natural Gas	$ 5.0	$ 12.3	$ 5.6	$ 0.1
Fuel Oil	—	—	0.6	—
FTRs	7.0	—	3.5	—
Coal	3.3	0.2	2.1	0.2
Total	$ 15.3	$ 12.5	$ 11.8	$ 0.3

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

	2014		2013	
	Volume	Gains	Volume	Gains (Losses)
		(Millions of Dollars)		(Millions of Dollars)
Natural Gas	40.5 million Dth	$ 7.3	48.6 million Dth	$ (8.5)
Fuel Oil	9.2 million gallons	0.5	8.6 million gallons	0.5
FTRs	26.1 million MWh	12.7	25.3 million MWh	14.9
Total		$ 20.5		$ 6.9

As of December 31, 2014 and 2013, we posted collateral of $11.2 million and zero, respectively, in our margin accounts. These amounts are recorded on the balance sheets in other current assets.

The fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral are not offset against the fair value amounts recognized for derivative instruments executed with the same counterparty under the same master netting arrangement. The table below shows derivative assets and derivative liabilities if derivative instruments by counterparty were presented net on the balance sheet as of December 31, 2014 and 2013.

	2014		2013	
	Derivative Asset	Derivative Liability	Derivative Asset	Derivative Liability
	(Millions of Dollars)			
Gross Amount Recognized on the Balance Sheet	$ 15.3	$ 12.5	$ 11.8	$ 0.3
Gross Amount Not Offset on Balance Sheet (a)	(0.4)	(11.5)	—	—
Net Amount	$ 14.9	$ 1.0	$ 11.8	$ 0.3

(a) Gross Amount Not Offset on Balance Sheet includes cash collateral posted of $10.3 million and zero as of December 31, 2014 and 2013, respectively.

M -- FAIR VALUE MEASUREMENTS

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

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

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

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

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

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

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

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

Recurring Fair Value Measures	As of December 31, 2014			
	Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Assets:				
Derivatives	$ 1.1	$ 7.2	$ 7.0	15.3
Total	$ 1.1	$ 7.2	$ 7.0	$ 15.3
Liabilities:				
Derivatives	$ 11.5	$ 1.0	$ —	$ 12.5
Total	$ 11.5	$ 1.0	$ —	$ 12.5

Recurring Fair Value Measures	As of December 31, 2013			
	Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Assets:				
Derivatives	$ 5.7	$ 2.6	$ 3.5	$ 11.8
Total	$ 5.7	$ 2.6	$ 3.5	$ 11.8
Liabilities:				
Derivatives	$ —	$ 0.3	$ —	$ 0.3
Total	$ —	$ 0.3	$ —	$ 0.3

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

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

	2014	2013
	(Millions of Dollars)	
Balance as of January 1	$ 3.5	$ 4.7
Realized and unrealized gains (losses)	—	—
Purchases	15.6	10.6
Issuances	—	—
Settlements	(12.1)	(11.8)
Transfers in and/or out of Level 3	—	—
Balance as of December 31	$ 7.0	$ 3.5

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

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

	2014		2013	
Financial Instruments	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(Millions of Dollars)			
Preferred stock, no redemption required	$ 30.4	$ 27.1	$ 30.4	$ 26.0
Long-term debt including current portion	$ 4,552.4	$ 5,126.0	$ 4,626.7	$ 4,911.8

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

N -- BENEFITS

Pensions and Other Post-retirement Benefits: We have defined benefit pension plans that cover substantially all of our employees. Generally, employees who started with the Company after 1995 receive a benefit based on a percentage of their annual salary plus an interest credit, while employees who started before 1996 receive a benefit based upon years of service and final average salary. Approximately half of our projected benefit obligation relates to benefits based upon years of service and final average salary. New management employees hired after December 31, 2014 will receive a 6% annual Company contribution to their 401(k) plan instead of being enrolled in the defined benefit plans.

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

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

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

	Pension		OPEB	
	2014	2013	2014	2013
	(Millions of Dollars)			
Change in Benefit Obligation				
Benefit Obligation at January 1	$ 1,410.2	$ 1,508.5	$ 362.7	$ 381.2
Service cost	10.1	14.6	8.5	10.0
Interest cost	68.1	60.4	17.8	15.6
Participants' contributions	—	—	9.1	8.9
Plan amendments	—	(1.0)	(4.6)	—
Actuarial loss (gain)	120.4	(81.9)	29.4	(27.7)
Gross benefits paid	(103.3)	(90.4)	(26.4)	(26.3)
Federal subsidy on benefits paid	N/A	N/A	1.2	1.0
Benefit Obligation at December 31	$ 1,505.5	$ 1,410.2	$ 397.7	$ 362.7
Change in Plan Assets				
Fair Value at January 1	$ 1,451.0	$ 1,385.4	$ 327.6	$ 285.4
Actual earnings on plan assets	88.5	147.3	17.7	45.5
Employer contributions	8.4	8.7	5.5	14.1
Participants' contributions	—	—	9.1	8.9
Gross benefits paid	(103.3)	(90.4)	(26.4)	(26.3)
Fair Value at December 31	$ 1,444.6	$ 1,451.0	$ 333.5	$ 327.6
Net liability (asset)	$ 60.9	$ (40.8)	$ 64.2	$ 35.1

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

	Pension		OPEB	
	2014	2013	2014	2013
	(Millions of Dollars)			
Other long-term assets	$ 39.2	$ 138.7	$ 39.5	$ 40.2
Other long-term liabilities	100.1	97.9	103.7	75.3
Net liability (asset)	$ 60.9	$ (40.8)	$ 64.2	$ 35.1

The accumulated benefit obligation for all defined pension plans was $1,504.6 million and $1,409.5 million as of December 31, 2014, and 2013, respectively.

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

	Pension		OPEB	
	2014	2013	2014	2013
	(Millions of Dollars)			
Net actuarial loss	$ 622.7	$ 528.8	$ 44.1	$ 9.8
Prior service costs (credits)	6.8	8.8	(4.6)	(1.7)
Total - Regulatory Assets	$ 629.5	$ 537.6	$ 39.5	$ 8.1

We estimate that 2015 periodic pension and OPEB costs will include the amortization of previously unrecognized benefit costs referred to above of $48.3 million and $0.9 million, respectively.

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

	Pension			OPEB		
	2014	2013	2012	2014	2013	2012
	(Millions of Dollars)					
Net Periodic Benefit Cost						
Service cost	$ 10.1	$ 14.6	$ 21.7	$ 8.5	$ 10.0	$ 10.3
Interest cost	68.1	60.4	65.5	17.8	15.6	20.3
Expected return on plan assets	(98.6)	(95.8)	(89.6)	(23.7)	(21.3)	(19.0)
Amortization of:						
Transition obligation	—	—	—	—	—	0.3
Prior service cost (credit)	2.1	2.3	2.2	(1.8)	(2.0)	(1.9)
Actuarial loss	36.7	54.5	41.0	1.2	3.7	7.3
Settlement charge	—	2.5	—	—	—	—
Other	—	—	0.4	—	—	—
Net Periodic Benefit Cost	$ 18.4	$ 38.5	$ 41.2	$ 2.0	$ 6.0	$ 17.3

	Pension			OPEB		
	2014	2013	2012	2014	2013	2012
Weighted-Average assumptions used to determine benefit obligations as of Dec. 31						
Discount rate	4.15%	5.00%	4.10%	4.20%	4.95%	4.15%
Rate of compensation increase	4.0%	4.0%	4.0%	N/A	N/A	N/A
Weighted-Average assumptions used to determine net cost for year ended Dec. 31						
Discount rate	5.00%	4.10%	5.05%	4.95%	4.15%	5.20%
Expected return on plan assets	7.25%	7.25%	7.25%	7.50%	7.50%	7.50%
Rate of compensation increase	4.0%	4.0%	4.0%	N/A	N/A	N/A

Assumed health care cost trend rates as of Dec. 31	2014	2013	2012
Health care cost trend rate assumed for next year (Pre 65 / Post 65)	7.5%/7.5%	7.5%/7.5%	7.5%/7.5%
Rate that the cost trend rate gradually adjusts to	5.0%	5.0%	5.0%
Year that the rate reaches the rate it is assumed to remain at (Pre 65 / Post 65)	2021/2021	2021/2021	2017/2017

The expected long-term rate of return on pension and OPEB plan assets was 7.25% and 7.50%, respectively, in 2014, 2013 and 2012. We consult with our investment advisors on an annual basis to help us forecast expected long-term returns on plan assets by reviewing historical returns as well as calculating expected total trust returns using the weighted-average of long-term market returns for each of the major target asset categories utilized in the fund.

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

	1% Increase	1% Decrease
	(Millions of Dollars)	
Effect on		
Post-retirement benefit obligation	$ 30.2	$ (25.4)
Total of service and interest cost components	$ 3.1	$ (2.5)

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

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

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

Previously, our pension plan target allocation was 45% equity investments and 55% fixed income investments. In late 2014, we began transitioning to a target asset allocation of 35% equity investments, 55% fixed income investments and 10% private equity and real estate investments. The current OPEB target asset allocation is 60% equity investments and 40% fixed income investments. Equity securities include investments in large-cap, mid-cap and small-cap companies primarily located in the United States. Fixed income securities include corporate bonds of companies from diversified industries, mortgage and other asset backed securities, commercial paper, and U.S. Treasuries.

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

	As of December 31, 2014			
Asset Category - Pension	Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Cash and Cash Equivalents	$ 6.4	$ —	$ —	$ 6.4
Equities:				
U.S. Equity	503.8	—	—	503.8
International Equity	128.6	29.8	—	158.4
Fixed Income				
Short, Intermediate and Long-term Bonds (a)				
U.S. Bonds	42.5	599.3	—	641.8
International Bonds	79.3	43.3	—	122.6
Private Equity and Real Estate	—	—	11.6	11.6
Total	$ 760.6	$ 672.4	$ 11.6	$ 1,444.6

	As of December 31, 2013			
Asset Category - Pension	Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Cash and Cash Equivalents	$ 21.0	$ —	$ —	$ 21.0
Equities:				
U.S. Equity	519.5	—	—	519.5
International Equity	146.2	35.7	—	181.9
Fixed Income				
Short, Intermediate and Long-term Bonds (a)				
U.S. Bonds	108.4	505.2	—	613.6
International Bonds	78.1	36.9	—	115.0
Total	$ 873.2	$ 577.8	$ —	$ 1,451.0

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

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

	As of December 31, 2014			
Asset Category - OPEB	Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Cash and Cash Equivalents	$ 1.4	$ —	$ —	$ 1.4
Equities:				
U.S. Equity	146.0	—	—	146.0
International Equity	42.2	2.5	—	44.7
Fixed Income:				
Short, Intermediate and Long-term Bonds (a)				
U.S. Bonds	3.5	112.4	—	115.9
International Bonds	17.5	7.0	—	24.5
Private Equity and Real Estate	—	—	1.0	1.0
Total	$ 210.6	$ 121.9	$ 1.0	$ 333.5

	As of December 31, 2013			
Asset Category - OPEB	Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Cash and Cash Equivalents	$ 2.6	$ —	$ —	$ 2.6
Equities:				
U.S. Equity	148.0	—	—	148.0
International Equity	46.9	2.8	—	49.7
Fixed Income:				
Short, Intermediate and Long-term Bonds (a)				
U.S. Bonds	8.4	96.3	—	104.7
International Bonds	16.8	5.8	—	22.6
Total	$ 222.7	$ 104.9	$ —	$ 327.6

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

In December 2014, our pension and OPEB plans began investing in private equity funds which are a Level 3 investment.

Cash Flows:

Historical employer contributions:

	Pension		
Year	Qualified	Non-Qualified	OPEB
	(Millions of Dollars)		
2012	$ 95.6	$ 7.1	$ 17.7
2013	$ —	$ 8.7	$ 14.1
2014	$ —	$ 8.4	$ 5.5

In January 2015, we contributed $100.0 million to the qualified pension plan. Future contributions to the plans will be dependent upon many factors, including the performance of plan assets, long-term discount rates and mortality rates.

Estimated benefit payments:

Year	Pension	Gross OPEB
	(Millions of Dollars)	
2015	$ 104.7	$ 25.5
2016	$ 103.6	$ 22.3
2017	$ 104.3	$ 22.8
2018	$ 102.3	$ 23.3
2019	$ 102.4	$ 24.1
2020-2024	$ 491.8	$ 122.5

Savings Plans: We sponsor savings plans which allow employees to contribute a portion of their pre-tax and/or after-tax income in accordance with plan-specified guidelines. Under these plans, we expensed matching contributions of $14.2 million, $14.2 million and $13.8 million during 2014, 2013 and 2012, respectively.

Postemployment Benefits: Postemployment benefits provided to former or inactive employees are recognized when an event occurs. The estimated liability for such benefits was $3.3 million and $4.2 million as of December 31, 2014 and 2013, respectively.

O -- SEGMENT REPORTING

Our reportable segments as of December 31, 2014 include a utility energy segment and a non-utility energy segment. We have organized our reportable segments based upon the regulatory environment in which our utility subsidiaries operate and on how management makes decisions and measures performance. The segments are managed separately because each business requires different technology and marketing strategies. The accounting policies of the reportable operating segments are the same as those described in Note A.

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

Summarized financial information concerning our reportable segments for each of the three years ended December 31, 2014 is shown in the following table.

	Reportable Segments			Eliminations	
	Energy		Corporate &	& Reconciling	Total
Year Ended	Utility	Non-Utility	Other (a)	Items	Consolidated
			(Millions of Dollars)		
December 31, 2014					
Operating Revenues (b)	$ 4,941.3	$ 447.1	$ 1.3	$ (392.6)	$ 4,997.1
Depreciation and Amortization	$ 340.6	$ 67.5	$ 0.7	$ —	$ 408.8
Operating Income (Loss)	$ 770.2	$ 368.2	$ (26.3)	$ —	$ 1,112.1
Equity in Earnings of Unconsolidated Affiliates	$ 66.0	$ —	$ (0.1)	$ —	$ 65.9
Interest Expense, Net	$ 128.8	$ 64.6	$ 48.8	$ (0.7)	$ 241.5
Income Tax Expense (Benefit)	$ 268.9	$ 121.4	$ (28.6)	$ —	$ 361.7
Net Income (Loss)	$ 447.2	$ 182.8	$ 588.0	$ (629.7)	$ 588.3
Capital Expenditures	$ 689.9	$ 41.1	$ 5.1	$ —	$ 736.1
Total Assets (c)	$ 14,912.8	$ 2,821.8	$ 4,880.3	$ (7,451.5)	$ 15,163.4

Year Ended	Reportable Segments: Energy: Utility	Reportable Segments: Energy: Non-Utility	Corporate & Other (a)	Eliminations & Reconciling Items	Total Consolidated
	(Millions of Dollars)				
December 31, 2013					
Operating Revenues (b)	$ 4,462.0	$ 446.7	$ 1.3	$ (391.0)	$ 4,519.0
Depreciation and Amortization	$ 320.2	$ 67.1	$ 0.8	$ —	$ 388.1
Operating Income (Loss)	$ 719.4	$ 367.1	$ (6.4)	$ —	$ 1,080.1
Equity in Earnings of Unconsolidated Affiliates	$ 68.5	$ —	$ (0.1)	$ —	$ 68.4
Interest Expense, Net	$ 136.2	$ 65.7	$ 50.8	$ (0.6)	$ 252.1
Income Tax Expense (Benefit)	$ 243.6	$ 120.2	$ (25.9)	$ —	$ 337.9
Net Income (Loss)	$ 425.1	$ 181.6	$ 577.2	$ (606.5)	$ 577.4
Capital Expenditures	$ 657.9	$ 26.1	$ 3.4	$ —	$ 687.4
Total Assets (c)	$ 14,460.4	$ 2,846.5	$ 4,719.5	$ (7,257.0)	$ 14,769.4
December 31, 2012					
Operating Revenues (b)	$ 4,190.8	$ 439.9	$ 1.2	$ (385.5)	$ 4,246.4
Depreciation and Amortization	$ 296.4	$ 67.1	$ 0.7	$ —	$ 364.2
Operating Income (Loss)	$ 647.7	$ 358.8	$ (6.2)	$ —	$ 1,000.3
Equity in Earnings of Unconsolidated Affiliates	$ 65.7	$ —	$ (0.2)	$ —	$ 65.5
Interest Expense, Net	$ 129.4	$ 66.7	$ 52.5	$ (0.4)	$ 248.2
Income Tax Expense (Benefit)	$ 214.9	$ 116.6	$ (25.2)	$ —	$ 306.3
Net Income (Loss)	$ 400.6	$ 175.9	$ 546.1	$ (576.3)	$ 546.3
Capital Expenditures	$ 697.3	$ 5.5	$ 4.2	$ —	$ 707.0
Total Assets (c)	$ 13,988.1	$ 2,903.5	$ 4,431.4	$ (7,038.0)	$ 14,285.0

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

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

(c) An elimination of $2,172.9 million, $2,231.2 million and $2,286.7 million is included in Total Assets as of December 31, 2014, 2013 and 2012, respectively, for all PTF-related activity between We Power and Wisconsin Electric.

P -- RELATED PARTIES

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

American Transmission Company LLC: As of December 31, 2014, we have a 26.2% interest in ATC. We pay ATC for transmission and other related services it provides. In addition, we provide a variety of operational, maintenance and project management work for ATC, which is reimbursed to us by ATC. We are required to pay the cost of needed transmission infrastructure upgrades for new generation projects while projects are under construction. ATC reimburses us for these costs when new generation is placed in service.

The following table summarizes material related party transactions with ATC during 2014, 2013 and 2012:

Equity Investee	2014	2013	2012
		(Millions of Dollars)	
Equity in Earnings	$ 66.0	$ 68.5	$ 65.7
Distributions Received	$ 57.5	$ 54.5	$ 52.6
Services Provided	$ 8.1	$ 9.0	$ 8.2
Services Received	$ 231.4	$ 234.2	$ 222.7

As of December 31, 2014 and 2013, our Consolidated Balance Sheets included receivable and payable balances with ATC as follows:

Equity Investee	2014	2013
	(Millions of Dollars)	
Accounts Receivable		
Services provided	$ 0.6	$ 0.6
Accounts Payable		
Services received	$ 19.3	$ 19.5

Q -- COMMITMENTS AND CONTINGENCIES

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

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

	(Millions of Dollars)
2015	$ 5.2
2016	3.9
2017	3.2
2018	3.1
2019	1.2
Thereafter	21.5
Total	$ 38.1

Divested Assets: We provided customary indemnifications to Wisconsin Power and Light Company, a subsidiary of Alliant Energy Corp. in connection with the sale of our interest in Edgewater Generating Unit 5.

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

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

Manufactured Gas Plant Sites: We have identified several sites at which Wisconsin Electric, Wisconsin Gas, or a predecessor company historically owned or operated a manufactured gas plant. These sites have been substantially remediated or are at various stages of investigation, monitoring and remediation. We have also identified other sites that may have been impacted by historical manufactured gas plant activities. Based upon on-going analysis, we estimate that the future costs for detailed site investigation and future remediation costs may range from $15 million to $47 million over the next ten years. This estimate is dependent upon several variables including, among other things, the extent of remediation, changes in technology and changes in regulation. As of December 31, 2014 and 2013, we established reserves of $32.6 million and $36.9 million, respectively, related to future remediation costs.

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

Coal Combustion Product Landfill Sites: Wisconsin Electric aggressively seeks environmentally acceptable, beneficial uses for its coal combustion products. However, some coal combustion products have been, and to a small degree continue to be, managed in company-owned, licensed landfills. Some early designed and constructed landfills have at times required various levels of monitoring or remediation. Where Wisconsin Electric has become aware of these conditions, efforts have been made to define the nature and extent of any release, and work has been performed to address these conditions. During 2014, 2013 and 2012, Wisconsin Electric incurred $0.1 million, $0.1 million and $0.3 million respectively, in landfill remediation expenses. As of December 31, 2014, we have no reserves established related to coal combustion product landfill sites.

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

R -- SUPPLEMENTAL CASH FLOW INFORMATION

During the year ended December 31, 2014, we paid $241.1 million in interest, net of amounts capitalized, and paid $22.0 million in income taxes, net of refunds. During the year ended December 31, 2013, we paid $250.4 million in interest, net of amounts capitalized, and received $39.6 million in net refunds from income taxes. During the year ended December 31, 2012, we paid $241.2 million in interest, net of amounts capitalized, and received $107.0 million in net refunds from income taxes.

As of December 31, 2014, 2013 and 2012, the amount of accounts payable related to capital expenditures was $1.8 million, $4.7 million and $15.7 million, respectively.

During the years ended December 31, 2014, 2013 and 2012, total amortization of deferred revenue was $55.7 million, $56.5 million and $54.9 million, respectively.

S -- SUBSEQUENT EVENT

On January 12, 2015, we entered into an agreement with the Governor of the State of Michigan, the Attorney General of the State of Michigan, the Staff of the MPSC and the owners of two large mines in the Upper Peninsula of Michigan, to resolve all objections these parties raised at the FERC and MPSC related to Wisconsin Energy's proposed acquisition of Integrys. We believe that this agreement is in the best interest of our customers. In connection with the agreement, we entered into a non-binding term sheet to sell our Michigan electric distribution assets and the Presque Isle Power Plant to a third party. The carrying value of these assets is approximately $292 million as of December 31, 2014.

We are working to achieve a definitive agreement for the sale of these assets by the end of March 2015. This agreement would be subject to approval by several regulatory agencies including FERC, the PSCW and the MPSC. If we are able to reach a definitive agreement consistent with the financial terms of the non-binding term sheet, we would seek the recovery of approximately $190 million of net unrecovered plant costs from our remaining customers.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Wisconsin Energy Corporation and subsidiaries (the "Company") as of December 31, 2014 and 2013, and the related consolidated income statements, statements of common equity, and statements of cash flows for each of the three years in the period ended December 31, 2014. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Wisconsin Energy Corporation and subsidiaries as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2014, based on the criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2015 expressed an unqualified opinion on the Company's internal control over financial reporting.

Deloitte & Touche LLP

February 27, 2015

Deloitte.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the internal control over financial reporting of Wisconsin Energy Corporation and subsidiaries (the "Company") as of December 31, 2014, based on the criteria established in *Internal Control—Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on the criteria established in *Internal Control—Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2014 of the Company and our report dated February 27, 2015 expressed an unqualified opinion on those financial statements.

Deloitte & Touche LLP

February 27, 2015

INTERNAL CONTROL OVER FINANCIAL REPORTING

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of Wisconsin Energy Corporation's and subsidiaries' internal control over financial reporting based on the framework in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its evaluation, our management concluded that Wisconsin Energy Corporation's and subsidiaries' internal control over financial reporting was effective as of December 31, 2014.

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

Deloitte & Touche LLP, an independent registered public accounting firm, as auditors of our financial statements has issued an attestation report on the effectiveness of Wisconsin Energy Corporation's and its subsidiaries' internal control over financial reporting as of December 31, 2014. Deloitte & Touche LLP's report is included in this report.

Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting during the fourth quarter of 2014 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

WISCONSIN ENERGY CORPORATION
CONSOLIDATED SELECTED FINANCIAL AND STATISTICAL DATA

Financial	2014	2013	2012	2011	2010
Year Ended December 31					
Net income - Continuing Operations (Millions)	$ 588.3	$ 577.4	$ 546.3	$ 512.8	$ 454.4
Earnings per share - Continuing Operations					
Basic	$ 2.61	$ 2.54	$ 2.37	$ 2.20	$ 1.94
Diluted	$ 2.59	$ 2.51	$ 2.35	$ 2.18	$ 1.92
Dividends per share of common stock	$ 1.56	$ 1.445	$ 1.20	$ 1.04	$ 0.80
Operating revenues (Millions)					
Utility energy	$ 4,941.3	$ 4,462.0	$ 4,190.8	$ 4,431.5	$ 4,165.3
Non-utility energy	447.1	446.7	439.9	435.1	320.2
Eliminations and Other	(391.3)	(389.7)	(384.3)	(380.2)	(283.0)
Total operating revenues	$ 4,997.1	$ 4,519.0	$ 4,246.4	$ 4,486.4	$ 4,202.5
As of December 31 (Millions)					
Total assets	$ 15,163.4	$ 14,769.4	$ 14,285.0	$ 13,862.1	$ 13,059.8
Long-term debt (including current maturities) and capital lease obligations	$ 4,610.5	$ 4,705.4	$ 4,865.9	$ 4,646.9	$ 4,405.4
Common Stock Closing Price	$ 52.74	$ 41.34	$ 36.85	$ 34.96	$ 29.43

CONSOLIDATED SELECTED QUARTERLY FINANCIAL DATA

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

	March		June	
Three Months Ended	2014	2013	2014	2013
Operating revenues	$ 1,695.0	$ 1,275.2	$ 1,043.7	$ 1,012.3
Operating income	$ 381.8	$ 321.0	$ 240.7	$ 229.5
Total net income	$ 207.6	$ 176.6	$ 133.0	$ 119.0
Earnings per share of common stock (b)				
Basic	$ 0.92	$ 0.77	$ 0.59	$ 0.52
Diluted	$ 0.91	$ 0.76	$ 0.58	$ 0.52

	September		December	
Three Months Ended	2014	2013	2014	2013
Operating revenues	$ 1,033.3	$ 1,053.2	$ 1,225.1	$ 1,178.3
Operating income	$ 246.1	$ 258.0	$ 243.5	$ 271.6
Total net income	$ 126.3	$ 137.5	$ 121.4	$ 144.3
Earnings per share of common stock (b)				
Basic	$ 0.56	$ 0.61	$ 0.54	$ 0.64
Diluted	$ 0.56	$ 0.60	$ 0.53	$ 0.63

(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.

PERFORMANCE GRAPH

The performance graph on the next page shows a comparison of the cumulative total return, assuming reinvestment of dividends, over the last five years had $100 been invested at the close of business on December 31, 2009, in each of:

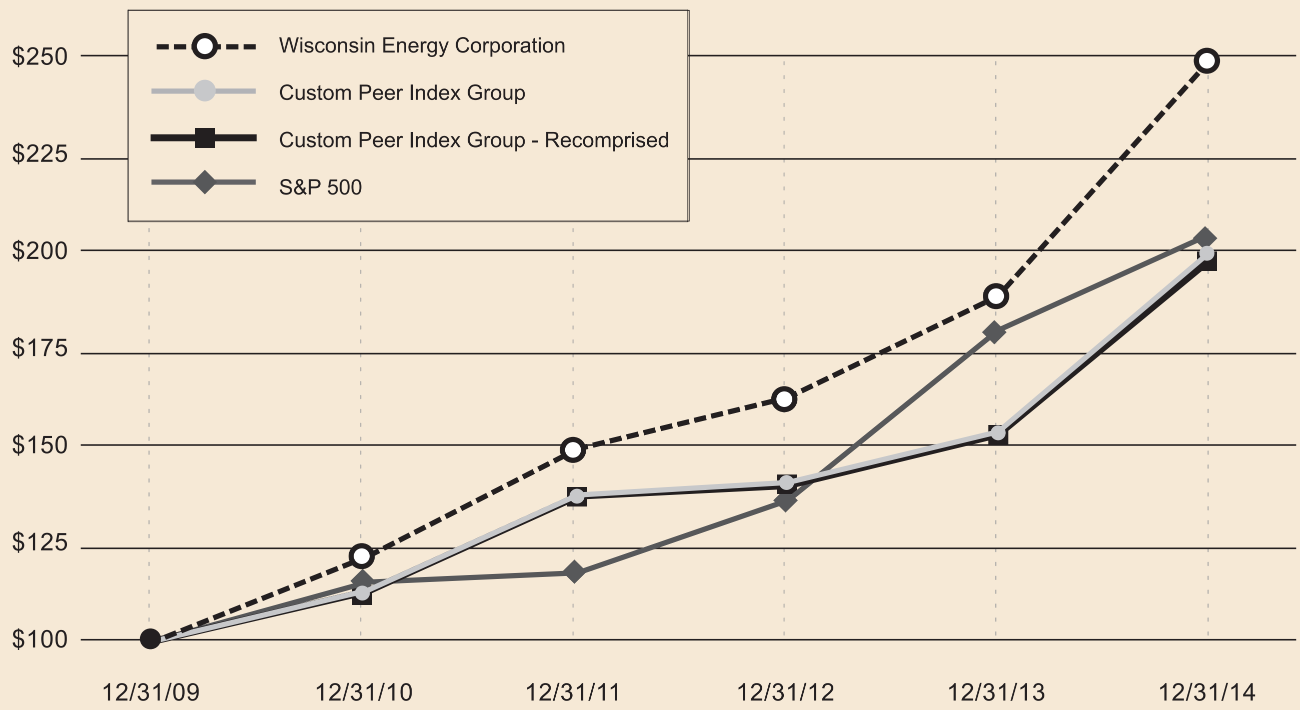
- Wisconsin Energy common stock;
- a Custom Peer Group Index;
- a recomprised Custom Peer Group Index; and
- the Standard & Poor's 500 Index ("S&P 500").

Custom Peer Group Index. We have used the Custom Peer Group Index for peer comparison purposes because we believed the Index provided an accurate representation of our peers. The Custom Peer Group Index is a market-capitalization-weighted index of companies, including Wisconsin Energy, that are similar to us in terms of business model and long-term strategies.

In addition to Wisconsin Energy, the companies in the Custom Peer Group Index are Alliant Energy Corporation; Ameren Corporation; American Electric Power Company, Inc.; Avista Corporation; CMS Energy Corporation, Consolidated Edison, Inc.; DTE Energy Company; Duke Energy Corp.; Eversource Energy (formerly known as Northeast Utilities); FirstEnergy Corp.; Great Plains Energy, Inc.; Integrys Energy Group, Inc.; NiSource Inc.; OGE Energy Corp.; Pepco Holdings, Inc.; PG&E Corporation; Pinnacle West Capital Corporation; Portland General; SCANA Corporation; The Southern Company; Westar Energy, Inc.; and Xcel Energy Inc.

Custom Peer Group Index – Recomprised. In April 2014 and June 2014, Exelon Corp. announced its acquisition of Pepco Holdings and we announced our acquisition of Integrys, respectively. Therefore, beginning in 2015, we have recomprised our custom peer group to remove PEPCO Holdings and Integrys as it is expected that these transactions will be completed during 2015. We have also added TECO Energy, Inc. to our custom peer group. We believe the Custom Peer Group Index, as recomprised, continues to be made up of companies that are similar to us in terms of business model and long-term strategies.

Five-Year Cumulative Return Chart



Value of Investment at Year-End

	12/31/09	12/31/10	12/31/11	12/31/12	12/31/13	12/31/14
Wisconsin Energy Corporation	$100	$122	$150	$163	$189	$250
Custom Peer Group Index	$100	$113	$138	$141	$154	$200
Custom Peer Group Index - Recomprised	$100	$113	$137	$140	$153	$198
S&P 500	$100	$115	$117	$136	$180	$205

MARKET FOR OUR COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

NUMBER OF COMMON STOCKHOLDERS

As of December 31, 2014, based upon the number of Wisconsin Energy Corporation stockholder accounts (including accounts in our dividend reinvestment and stock purchase plan), we had approximately 38,110 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.

On January 15, 2015, the Board of Directors increased the quarterly dividend to $0.4225 per share effective with the first quarter of 2015 dividend payment, which would result in annual dividends of $1.69 per share. In addition, the Board affirmed our dividend policy that targets a dividend payout ratio of 65-70% of earnings in 2017.

Range of Wisconsin Energy Common Stock Prices and Dividends:

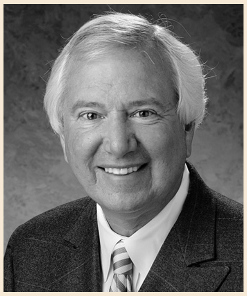
	2014			2013		
Quarter	High	Low	Dividend	High	Low	Dividend
First	$ 46.76	$ 40.17	$ 0.39	$ 42.95	$ 37.03	$ 0.3400
Second	$ 49.21	$ 44.03	0.39	$ 45.00	$ 39.04	0.3400
Third	$ 47.02	$ 41.90	0.39	$ 44.01	$ 39.52	0.3825
Fourth	$ 55.39	$ 43.01	0.39	$ 43.00	$ 39.83	0.3825
Annual	$ 55.39	$ 40.17	$ 1.56	$ 45.00	$ 37.03	$ 1.4450

BOARD OF DIRECTORS

John F. Bergstrom
Director since 1987.
Chairman and Chief Executive Officer of Bergstrom Corporation, which owns and operates numerous automobile sales and leasing companies.

Barbara L. Bowles
Director since 1998.
Retired Vice Chair of Profit Investment Management and Retired Chairman of The Kenwood Group, Inc., investment advisory firms. The Kenwood Group, Inc. was merged into Profit Investment Management in 2006.

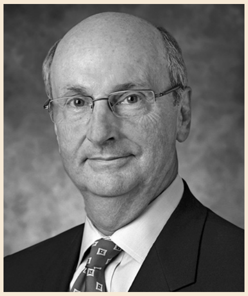
Patricia W. Chadwick
Director since 2006.
President of Ravengate Partners, LLC, which provides businesses and not-for-profit institutions with advice about the economy and the financial markets.



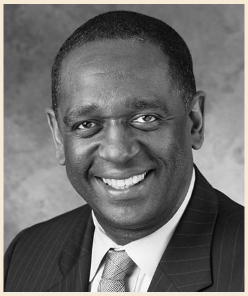
Curt S. Culver
Director since 2004.
Non-Executive Chairman of the Board of MGIC Investment Corporation and Mortgage Guaranty Insurance Corporation, a private mortgage insurance company.

Thomas J. Fischer
Director since 2005.
Principal of Fischer Financial Consulting LLC, which provides consulting on corporate financial, accounting and governance matters.

Gale E. Klappa
Director since 2003.
Chairman and Chief Executive Officer of Wisconsin Energy Corporation.



Henry W. Knueppel
Director since 2013.
Retired Chairman and Chief Executive Officer of Regal Beloit Corporation, a manufacturer of electrical and mechanical motion control products.



Ulice Payne, Jr.
Director since 2003.
Managing Member of Addison-Clifton, LLC, which provides global trade compliance advisory services.

Mary Ellen Stanek
Director since 2012.
Managing Director and Director of Asset Management of Baird Financial Group; Chief Investment Officer, Baird Advisors; President, Baird Funds, Inc. Baird Financial Group provides wealth management, capital markets, private equity and asset management services to clients worldwide.

OFFICERS

The names and positions as of December 31, 2014 of Wisconsin Energy's officers are listed below.

Gale E. Klappa[(1)] – Chairman of the Board and Chief Executive Officer.

Allen L. Leverett[(1)] – President.

J. Patrick Keyes[(1)] – Executive Vice President and Chief Financial Officer.

Susan H. Martin[(1)] – Executive Vice President, General Counsel and Corporate Secretary.

Robert M. Garvin[(1)] – Senior Vice President – External Affairs.

Darnell K. DeMasters – Vice President – Federal Policy.

Stephen P. Dickson[(1)] – Vice President and Controller.

Walter J. Kunicki – Vice President.

Scott J. Lauber – Vice President and Treasurer.

Keith H. Ecke – Assistant Corporate Secretary.

David L. Hughes – Assistant Treasurer.

[(1)] Executive Officers of Wisconsin Energy Corporation as of December 31, 2014. Kevin Fletcher, Senior Vice President of Wisconsin Electric Power Company and Wisconsin Gas LLC, is also an executive officer of Wisconsin Energy Corporation.

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STOCKHOLDER INFORMATION

ACCOUNT INFORMATION

- Visit **www.computershare.com/investor.** Wisconsin Energy's transfer agent, Computershare, provides our registered stockholders with secure account access. Stockholders can view share balances, market value, tax documents and account statements; review answers to frequently asked questions; perform many transactions; and sign up for eDelivery, the paperless communication program from Computershare. eDelivery also provides electronic delivery of your annual meeting materials.

- Write to:
  Wisconsin Energy Corporation
  c/o Computershare
  P.O. Box 30170
  College Station, TX 77842-3170

- If sending overnight correspondence, mail to:
  Wisconsin Energy Corporation
  c/o Computershare
  211 Quality Circle, Suite 210
  College Station, TX 77845

- Call Computershare at **800-558-9663**. Service representatives are available from 7 a.m. to 7 p.m. Central time on business days. An automated voice-response system also provides information 24 hours a day, seven days a week.

Securities analysts and institutional investors may contact our Investor Relations Line at **414-221-2592**. Stockholders who hold Wisconsin Energy stock in brokerage accounts should contact their brokerage firm for account information.

STOCK PURCHASE PLAN

Wisconsin Energy's Stock Plus Investment Plan provides a convenient way to purchase our common stock and reinvest dividends. To review the Prospectus and enroll, go to **wisconsinenergy.com** and select the Investors tab. You also may contact Computershare at **800-558-9663** to request an enrollment package. This is not an offer to sell, or a solicitation of an offer to buy, any securities. Any stock offering will be made only by Prospectus.

DIVIDENDS

Dividends, as declared by the board of directors, typically are payable on the first day of March, June, September and December. Stockholders may have their dividends deposited directly into their bank accounts. Please contact Computershare to request an authorization form.

INTERNET ACCESS HELPS REDUCE COSTS

You may access **wisconsinenergy.com** for the latest information about Wisconsin Energy Corporation. The site provides access to financial, corporate governance and other information, including Securities and Exchange Commission reports.

ANNUAL CERTIFICATIONS

Wisconsin Energy has filed the required certifications of its Chief Executive Officer and Chief Financial Officer under the Sarbanes-Oxley Act regarding the quality of its public disclosures. These exhibits can be found in the company's Form 10-K for the year ended Dec. 31, 2014. The certification of Wisconsin Energy's Chief Executive Officer regarding compliance with the New York Stock Exchange (NYSE) corporate governance listing standards will be filed with the NYSE following the 2015 Annual Meeting of Stockholders. Last year, we filed this certification on May 30, 2014.

CORPORATE SOCIAL RESPONSIBILITY

Wisconsin Energy is committed to corporate social responsibility and sustainable business practices — aligning our policies and practices with the needs of key stakeholders, and managing risk while accounting for the company's economic, environmental and social impacts. For additional information, visit **www.wisconsinenergy.com/csr**.

Wisconsin Energy Corporation

Wisconsin Energy Corporation

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