WISCONSIN ENERGY CORP
Form 10-Q
August 01, 2014

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

FORM 10-Q

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

For the Quarterly Period Ended June 30, 2014

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).   Yes [X]   No [ ]

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

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

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

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date (June 30, 2014):

Common Stock, $.01 Par Value,	225,518,628 shares outstanding.

Form 10-Q

WISCONSIN ENERGY CORPORATION

FORM 10-Q REPORT FOR THE QUARTER ENDED JUNE 30, 2014

TABLE OF CONTENTS

Form 10-Q

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
Federal and State Regulatory Agencies	
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
MDEQ	Michigan Department of Environmental Quality
PSCW	Public Service Commission of Wisconsin
SEC	Securities and Exchange Commission
WDNR	Wisconsin Department of Natural Resources
Environmental Terms	
BART	Best Available Retrofit Technology
BTA	Best Technology Available
CAIR	Clean Air Interstate Rule
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
NOV	Notice of Violation
NO_x	Nitrogen Oxide
PSD	Prevention of Significant Deterioration
SIP	State Implementation Plan
SO_2	Sulfur Dioxide

Other Terms and Abbreviations

ARRs	Auction Revenue Rights

Form 10-Q

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:

Bechtel	Bechtel Power Corporation
Compensation Committee	Compensation Committee of the Board of Directors
Exchange Act	Securities Exchange Act of 1934, as amended
FTRs	Financial Transmission Rights
GCRM	Gas Cost Recovery Mechanism
HSR	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 Investors Service
OTC	Over-the-Counter
PTF	Power the Future
S&P	Standard and Poor's Ratings Services
SSR	System Support Resource
Treasury Grant	Section 1603 Renewable Energy Treasury Grant

Measurements

Btu	British Thermal Unit(s)
Dth	Dekatherm(s) (One Dth equals one million Btu)
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
GAAP	Generally Accepted Accounting Principles
OPEB	Other Post-Retirement Employee Benefits

Form 10-Q

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" or similar terms or variations of these terms.

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

- Factors affecting utility operations such as catastrophic weather-related or terrorism-related damage; cyber security threats and disruptions to our technology network; availability of electric generating facilities; unscheduled generation outages, or unplanned maintenance or repairs; unanticipated events causing scheduled generation outages to last longer than expected; unanticipated changes in fossil fuel, purchased power, coal supply, gas supply or water supply costs or availability due to higher demand, shortages, transportation problems or other developments; unanticipated changes in the cost or availability of materials needed to operate environmental controls at our electric generating facilities or replace and/or repair our electric and gas distribution systems; nonperformance by electric energy or natural gas suppliers under existing power purchase or gas supply contracts; environmental incidents; electric transmission or gas pipeline system constraints; unanticipated organizational structure or key personnel changes; or collective bargaining agreements with union employees or work stoppages.

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

- Timing, resolution and impact of rate cases and negotiations.

- The impact across our service territories of the continued adoption of distributed generation by our electric customers, and our ability to design and implement an appropriate rate structure to mitigate these impacts.

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

- Our ability to continue to mitigate the impact of Michigan customers switching to an alternative electric supplier.

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

- The impact of recent and future federal, state and local legislative and regulatory changes, including any changes in rate-setting policies or procedures; regulatory initiatives regarding deregulation and restructuring of the electric and/or gas utility industry; transmission or distribution system operation and/or administration initiatives; any required changes in facilities or operations to reduce the risks or impacts of potential terrorist activities or cyber security threats; the regulatory approval process for new generation and transmission facilities and new pipeline construction; adoption of new, or changes in existing, environmental, federal and state energy, tax and other laws and regulations to which we may become, or are, subject; changes in allocation of energy assistance, including state public benefits funds; changes in the application or enforcement of existing laws and regulations; and changes in the interpretation or enforcement of permit conditions by the permitting agencies.

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

- Current and future litigation, regulatory investigations, proceedings or inquiries.

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

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

- Inflation rates.

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

- The financial performance of American Transmission Company LLC (ATC) and its corresponding contribution to our earnings, as well as the ability of ATC and the Duke-American Transmission Company 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 shareholder, 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 business or investment considerations that may be disclosed from time to time in our Securities and Exchange Commission (SEC) filings or in other publicly disseminated written documents, including the risk factors set forth in our Annual Report on Form 10-K for the year ended December 31, 2013 as updated in Item 1A. Risk Factors in Part II of this report.

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

INTRODUCTION

Wisconsin Energy Corporation (Wisconsin Energy) is a diversified holding company which conducts its operations primarily in two reportable segments: a utility energy segment and a non-utility energy segment. Unless qualified by their context when used in this document, the terms the Company, our, us or we refer to the holding company and all of its subsidiaries. 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, which serves electric customers in Wisconsin and the Upper Peninsula of Michigan, gas customers in Wisconsin and steam customers in metropolitan Milwaukee, Wisconsin; and Wisconsin Gas, which serves gas customers in Wisconsin. Wisconsin Electric and Wisconsin Gas operate under the trade name of "We Energies."

Non-Utility Energy Segment: Our non-utility energy segment consists primarily of We Power, which owns and leases to Wisconsin Electric the new generating capacity included in our Power the Future (PTF) strategy. See Item 1. Business and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations in our 2013 Annual Report on Form 10-K for more information on PTF.

We have prepared the unaudited interim financial statements presented in this Form 10-Q pursuant to the rules and regulations of the SEC. We have condensed or omitted some information and note disclosures normally included in financial statements prepared in accordance with Generally Accepted Accounting Principles (GAAP) pursuant to these rules and regulations. This Form 10-Q, including the financial statements contained herein, should be read in conjunction with our 2013 Annual Report on Form 10-K, including the financial statements and notes therein.

Form 10-Q

PART I -- FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

WISCONSIN ENERGY CORPORATION
CONSOLIDATED CONDENSED INCOME STATEMENTS
(Unaudited)

	Three Months Ended June 30		Six Months Ended June 30	
	2014	2013	2014	2013
	(Millions of Dollars, Except Per Share Amounts)			
Operating Revenues	$1,043.7	$1,012.3	$2,738.7	$2,287.5
Operating Expenses				
Fuel and purchased power	292.5	276.1	611.1	547.1
Cost of gas sold	125.9	115.2	717.4	385.3
Other operation and maintenance	256.0	265.4	531.4	553.5
Depreciation and amortization	101.4	96.7	202.0	192.2
Property and revenue taxes	30.3	29.4	60.9	58.9
Total Operating Expenses	806.1	782.8	2,122.8	1,737.0
Treasury Grant	3.1	—	6.6	—
Operating Income	240.7	229.5	622.5	550.5
Equity in Earnings of Transmission Affiliate	17.5	17.3	34.8	33.9
Other Income, net	8.1	5.8	9.2	10.2
Interest Expense, net	59.0	63.3	121.3	128.3
Income Before Income Taxes	207.3	189.3	545.2	466.3
Income Tax Expense	74.3	70.3	204.6	170.7
Net Income	$133.0	$119.0	$340.6	$295.6
Earnings Per Share				
Basic	$0.59	$0.52	$1.51	$1.29
Diluted	$0.58	$0.52	$1.50	$1.28
Weighted Average Common Shares Outstanding (Millions)				
Basic	225.5	228.4	225.6	228.6
Diluted	227.6	230.5	227.7	230.8
Dividends Per Share of Common Stock	$0.39	$0.34	$0.78	$0.68

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

Form 10-Q

WISCONSIN ENERGY CORPORATION
CONSOLIDATED CONDENSED BALANCE SHEETS
(Unaudited)

	June 30, 2014	December 31, 2013
	(Millions of Dollars)	
Assets		
Property, Plant and Equipment		
In service	$15,179.5	$14,966.3
Accumulated depreciation	(4,384.4)	(4,257.1)
	10,795.1	10,709.2
Construction work in progress	183.9	149.6
Leased facilities, net	45.0	47.8
Net Property, Plant and Equipment	11,024.0	10,906.6
Investments		
Equity investment in transmission affiliate	416.8	402.7
Other	35.3	36.1
Total Investments	452.1	438.8
Current Assets		
Cash and cash equivalents	33.4	26.0
Accounts receivable, net	404.9	406.0
Accrued revenues	174.8	321.1
Materials, supplies and inventories	304.3	329.4
Current deferred tax asset, net	199.3	310.0
Prepayments and other	168.8	158.6
Total Current Assets	1,285.5	1,551.1
Deferred Charges and Other Assets		
Regulatory assets	1,094.9	1,108.5
Goodwill	441.9	441.9
Other	321.4	322.5
Total Deferred Charges and Other Assets	1,858.2	1,872.9
Total Assets	$14,619.8	$14,769.4
Capitalization and Liabilities		
Capitalization		
Common equity	$4,367.1	$4,233.0
Preferred stock of subsidiary	30.4	30.4
Long-term debt	4,587.5	4,363.2
Total Capitalization	8,985.0	8,626.6
Current Liabilities		
Long-term debt due currently	45.1	342.2
Short-term debt	410.1	537.4
Accounts payable	288.5	342.6
Accrued payroll and benefits	70.4	96.9
Other	166.7	177.3
Total Current Liabilities	980.8	1,496.4
Deferred Credits and Other Liabilities		
Regulatory liabilities	854.9	879.1
Deferred income taxes - long-term	2,714.6	2,634.0

Deferred revenue, net	639.7	664.2
Pension and other benefit obligations	169.3	173.2
Other	275.5	295.9
Total Deferred Credits and Other Liabilities	4,654.0	4,646.4
Total Capitalization and Liabilities	$14,619.8	$14,769.4

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

Form 10-Q

WISCONSIN ENERGY CORPORATION
CONSOLIDATED CONDENSED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six Months Ended June 30	
	2014	2013
	(Millions of Dollars)	
Operating Activities		
Net income	$340.6	$295.6
Reconciliation to cash		
Depreciation and amortization	206.5	197.7
Deferred income taxes and investment tax credits, net	188.0	143.1
Change in - Accounts receivable and accrued revenues	132.0	49.3
Inventories	25.1	42.8
Other current assets	11.8	13.8
Accounts payable	(52.6)	(86.6)
Accrued income taxes, net	(10.6)	16.2
Other current liabilities	(21.6)	(2.9)
Other, net	(97.9)	12.5
Cash Provided by Operating Activities	721.3	681.5
Investing Activities		
Capital expenditures	(305.5)	(307.3)
Investment in transmission affiliate	(7.9)	(5.2)
Other, net	0.5	(24.1)
Cash Used in Investing Activities	(312.9)	(336.6)
Financing Activities		
Exercise of stock options	17.6	40.7
Purchase of common stock	(57.3)	(135.7)
Dividends paid on common stock	(176.0)	(155.6)
Issuance of long-term debt	250.0	250.0
Retirement of long-term debt	(311.1)	(310.5)
Change in short-term debt	(127.3)	(58.7)
Other, net	3.1	10.3
Cash Used in Financing Activities	(401.0)	(359.5)
Change in Cash and Cash Equivalents	7.4	(14.6)
Cash and Cash Equivalents at Beginning of Period	26.0	35.6
Cash and Cash Equivalents at End of Period	$33.4	$21.0

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

Form 10-Q

WISCONSIN ENERGY CORPORATION
NOTES TO CONSOLIDATED CONDENSED FINANCIAL STATEMENTS
(Unaudited)

1 -- GENERAL INFORMATION

Our accompanying unaudited consolidated condensed financial statements should be read in conjunction with Item 8. Financial Statements and Supplementary Data, in our 2013 Annual Report on Form 10-K. In the opinion of management, we have included all adjustments, normal and recurring in nature, necessary for a fair presentation of the results of operations, cash flows and financial position in the accompanying income statements, statements of cash flows and balance sheets. The results of operations for the three and six months ended June 30, 2014 are not necessarily indicative of the results which may be expected for the entire fiscal year 2014 because of seasonal and other factors.

2 -- NEW 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 (ASU) 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.

3 -- 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 (Acquisition). Integrys' shareholders will receive 1.128 shares of Wisconsin Energy common stock and $18.58 in cash per Integrys share of common stock, with the total consideration valued at approximately $5.8 billion, based upon the value of our common stock as of June 30, 2014. 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 the Federal Energy Regulatory Commission (FERC), Federal Communications Commission, Public Service Commission of Wisconsin (PSCW), Illinois Commerce Commission, Michigan Public Service Commission and Minnesota Public Utilities Commission. The cash consideration will be financed through the issuance of approximately $1.5 billion of debt at the holding company level. We anticipate the transaction closing in the second half of 2015.

Form 10-Q

4 -- COMMON EQUITY

Stock Option Activity: The following table identifies non-qualified stock options granted by the Compensation Committee of the Board of Directors (Compensation Committee):

	2014		2013	
Non-qualified stock options granted year to date	899,500		1,418,560	
Estimated fair value per non-qualified stock option	$4.18		$3.45	
Assumptions used to value the options using a binomial option pricing model:				
Risk-free interest rate	0.1% - 3.0%		0.1% - 1.9%	
Dividend yield	3.8	%	3.7	%
Expected volatility	18.0	%	18.0	%
Expected forfeiture rate	2.0	%	2.0	%
Expected life (years)	5.8		5.9	

The risk-free interest rate is based on the U.S. Treasury interest rate whose term is consistent with the expected life of the stock options. Dividend yield, expected volatility, expected forfeiture rate and expected life assumptions are based on our historical experience.

The following is a summary of our stock option activity for the three and six months ended June 30, 2014:

Stock Options	Number of Options		Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (Millions)
Outstanding as of April 1, 2014	8,276,994		$28.82		
Granted	—		$—		
Exercised	(96,791	)	$24.07		
Forfeited	(10,810	)	$37.94		
Outstanding as of June 30, 2014	8,169,393		$28.87		
Outstanding as of January 1, 2014	8,089,710		$26.84		
Granted	899,500		$41.03		
Exercised	(802,622	)	$21.89		
Forfeited	(17,195	)	$36.73		
Outstanding as of June 30, 2014	8,169,393		$28.87	5.6	$147.5
Exercisable as of June 30, 2014	5,253,148		$23.82	3.9	$121.3

The intrinsic value of options exercised was $2.2 million and $17.5 million for the three and six months ended June 30, 2014, and $11.6 million and $36.0 million for the same periods in 2013, respectively. Cash received from options exercised was $17.6 million and $40.7 million for the six months ended June 30, 2014 and 2013, respectively. The actual tax benefit realized for the tax deductions from option exercises for the same periods was $7.0 million and $14.4 million, respectively.

All outstanding stock options to purchase shares of common stock were included in the computation of diluted earnings per share during the second quarter of 2014.

Form 10-Q

The following table summarizes information about stock options outstanding as of June 30, 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	1,682,973	$20.67	3.8	1,682,973	$20.67	3.8
$23.88 to $29.35	3,356,060	$24.66	3.7	3,356,060	$24.66	3.7
$34.88 to $41.03	3,130,360	$37.78	8.5	214,115	$35.50	7.7
	8,169,393	$28.87	5.6	5,253,148	$23.82	3.9

The following table summarizes information about our non-vested options during the three and six months ended June 30, 2014:

Non-Vested Stock Options	Number of Options	Weighted-Average Fair Value
Non-vested as of April 1, 2014	2,939,015	$3.65
Granted	—	$—
Vested	(11,960)	$3.65
Forfeited	(10,810)	$3.65
Non-vested as of June 30, 2014	2,916,245	$3.65
Non-vested as of January 1, 2014	2,380,790	$3.38
Granted	899,500	$4.18
Vested	(346,850)	$3.22
Forfeited	(17,195)	$3.56
Non-vested as of June 30, 2014	2,916,245	$3.65

As of June 30, 2014, total compensation costs related to non-vested stock options not yet recognized was approximately $3.9 million, which is expected to be recognized over the next 19 months on a weighted-average basis.

Restricted Shares: The following restricted stock activity occurred during the three and six months ended June 30, 2014:

Restricted Shares	Number of Shares	Weighted-Average Grant Date Fair Value
Outstanding as of April 1, 2014	157,595	
Granted	—	$—
Released	—	$—
Forfeited	(827)	$38.83
Outstanding as of June 30, 2014	156,768	
Outstanding as of January 1, 2014	150,698	
Granted	71,504	$40.96
Released	(63,509)	$33.02
Forfeited	(1,925)	$38.38
Outstanding as of June 30, 2014	156,768	

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 zero and

$2.7 million for the three and six months ended June 30, 2014, and $0.8 million and $4.0 million for the same periods in 2013, respectively. The actual tax benefit realized for the tax deductions from released restricted shares was zero and $1.0 million for the three and six months ended June 30, 2014, and $0.2 million and $1.3 million for the same periods in 2013, respectively.

As of June 30, 2014, total compensation cost related to restricted stock not yet recognized was approximately $4.1 million, which is expected to be recognized over the next 24 months on a weighted-average basis.

Performance Units: In January 2014 and 2013, the Compensation Committee granted 233,735 and 239,120 performance units, respectively, to officers and other key employees under the Wisconsin Energy Performance Unit Plan. Performance units earned as of December 31, 2013 and 2012 vested and were settled during the first quarter of 2014 and 2013, and had a total intrinsic value of $14.8 million and $19.3 million, respectively. The actual tax benefit realized for the tax deductions from the settlement of performance units was approximately $5.3 million and $7.0 million, respectively. As of June 30, 2014, total compensation cost related to performance units not yet recognized was approximately $12.8 million, which is expected to be recognized over the next 25 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 us 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. See Note H -- Common Equity in our 2013 Annual Report on Form 10-K for additional information on these and other restrictions.

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

Share Repurchase Program: In December 2013, our Board of Directors authorized a share repurchase program for the purchase of up to $300 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 Acquisition, the Board of Directors terminated this share repurchase program. The previous share repurchase program authorized by our Board of Directors expired at the end of 2013. For the six months ended June 30, 2014, we repurchased $18.6 million of our common stock pursuant to the recently terminated program at an average cost of $43.66 per share. All of these shares were purchased during the first quarter of 2014. 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 shares purchased in the following periods:

	Six Months Ended June 30			
	2014		2013	
	Shares	Cost	Shares	Cost
	(In Millions)			
Under share repurchase programs	0.4	$18.6	1.3	$54.7
To fulfill exercised stock options and restricted stock awards	0.9	38.7	2.0	81.0
Total	1.3	$57.3	3.3	$135.7

5 -- LONG-TERM DEBT

In May 2014, Wisconsin Electric issued $250 million of 4.25% Debentures due June 1, 2044. The debentures were issued under an existing shelf registration statement filed with the SEC in November 2013. The net proceeds were used to repay short-term debt and for general corporate purposes.

On April 1, 2014, Wisconsin Electric used short-term borrowings to retire $300 million of long-term debt that matured.

Form 10-Q

In June 2013, Wisconsin Electric issued $250 million of 1.70% Debentures due June 15, 2018. The debentures were issued under an existing shelf registration statement filed with the SEC in February 2011. The net proceeds were used to repay short-term debt and for other corporate purposes.

On May 15, 2013, Wisconsin Electric used short-term borrowings to retire $300 million of long-term debt that matured.

6 -- 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 June 30, 2014			
	Level 1	Level 2	Level 3	Total

	(Millions of Dollars)			
Assets:				
Derivatives	$2.2	$6.6	$14.1	$22.9
Total	$2.2	$6.6	$14.1	$22.9
Liabilities:				
Derivatives	$—	$0.2	$—	$0.2
Total	$—	$0.2	$—	$0.2

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:

	Three Months Ended June 30		Six Months Ended June 30	
	2014	2013	2014	2013
	(Millions of Dollars)			
Beginning Balance	$1.7	$1.6	$3.5	$4.7
Realized and unrealized gains (losses)	—	—	—	—
Purchases	15.6	10.6	15.6	10.6
Issuances	—	—	—	—
Settlements	(3.2)	(3.0)	(5.0)	(6.1)
Transfers in and/or out of Level 3	—	—	—	—
Balance as of June 30	$14.1	$9.2	$14.1	$9.2
Change in unrealized gains (losses) relating to instruments still held as of June 30	$—	$—	$—	$—

Derivative instruments reflected in Level 3 of the hierarchy include Midcontinent Independent System Operator, Inc. (MISO) Financial Transmission Rights (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 7 -- Derivative Instruments, for further information on the offset to regulatory assets and liabilities.

Form 10-Q

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

Financial Instruments	June 30, 2014 Carrying Amount (Millions of Dollars)	Fair Value	December 31, 2013 Carrying Amount	Fair Value
Preferred stock, no redemption required	$30.4	$25.8	$30.4	$26.0
Long-term debt, including current portion	$4,565.6	$4,995.4	$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.

7 -- 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 June 30, 2014, we recognized $1.3 million in regulatory assets and $21.5 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 prepayments and other current assets and the current portion of the liabilities in other current liabilities. As of June 30, 2014, none of our derivative assets or derivative liabilities were considered long-term. Our Consolidated Condensed Balance Sheets as of June 30, 2014 and December 31, 2013 include:

	June 30, 2014 Derivative Asset (Millions of Dollars)	Derivative Liability	December 31, 2013 Derivative Asset	Derivative Liability
Natural Gas	$7.4	$—	$5.6	$0.1
Fuel Oil	0.2	—	0.6	—
FTRs	14.1	—	3.5	—
Coal	1.2	0.2	2.1	0.2
Total	$22.9	$0.2	$11.8	$0.3

Our Consolidated Condensed 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) were as follows:

	Three Months Ended June 30, 2014		Three Months Ended June 30, 2013	
	Volume	Gains (Losses) (Millions of Dollars)	Volume	Gains (Losses) (Millions of Dollars)
Natural Gas	9.9 million Dth	$2.5	11.3 million Dth	$1.9
Fuel Oil	2.4 million gallons	0.4	2.2 million gallons	0.1
FTRs	7.4 million MWh	2.6	6.5 million MWh	4.7
Total		$5.5		$6.7
	Six Months Ended June 30, 2014		Six Months Ended June 30, 2013	
	Volume	Gains (Losses) (Millions of Dollars)	Volume	Gains (Losses) (Millions of Dollars)
Natural Gas	24.8 million Dth	$10.1	30.1 million Dth	$(4.6)
Fuel Oil	4.4 million gallons	0.6	3.7 million gallons	0.2
FTRs	13.1 million MWh	9.6	12.3 million MWh	5.6
Total		$20.3		$1.2

As of June 30, 2014 and December 31, 2013, we posted collateral of $0.2 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 June 30, 2014 and December 31, 2013.

	June 30, 2014		December 31, 2013	
	Derivative Asset	Derivative Liability	Derivative Asset	Derivative Liability
	(Millions of Dollars)			
Gross Amount Recognized on the Balance Sheet	$22.9	$0.2	$11.8	$0.3
Gross Amount Not Offset on Balance Sheet (a)	—	—	—	—
Net Amount	$22.9	$0.2	$11.8	$0.3

(a) Gross Amount Not Offset on Balance Sheet includes no cash collateral posted as of June 30, 2014 and December 31, 2013.

Form 10-Q

8 -- BENEFITS

The components of our net periodic pension and Other Post-Retirement Employee Benefits (OPEB) costs for the three and six months ended June 30 were as follows:

	Pension Costs			
	Three Months Ended June 30		Six Months Ended June 30	
Benefit Plan Cost Components	2014	2013	2014	2013
	(Millions of Dollars)			
Net Periodic Benefit Cost				
Service cost	$2.3	$3.1	$5.0	$7.3
Interest cost	17.0	15.1	34.1	30.2
Expected return on plan assets	(24.6)	(23.9)	(49.3)	(47.9)
Amortization of:				
Prior service cost	0.5	0.6	1.0	1.2
Actuarial loss	9.3	13.6	18.4	27.2
Net Periodic Benefit Cost	$4.5	$8.5	$9.2	$18.0

	OPEB Costs			
	Three Months Ended June 30		Six Months Ended June 30	
Benefit Plan Cost Components	2014	2013	2014	2013
	(Millions of Dollars)			
Net Periodic Benefit Cost				
Service cost	$2.1	$2.3	$4.3	$5.0
Interest cost	4.4	3.9	8.9	7.8
Expected return on plan assets	(6.0)	(5.3)	(11.9)	(10.6)
Amortization of:				
Transition obligation	—	—	—	—
Prior service (credit)	(0.4)	(0.5)	(0.9)	(1.0)
Actuarial loss	0.4	0.9	0.6	1.8
Net Periodic Benefit Cost	$0.5	$1.3	$1.0	$3.0

We made no contributions to our qualified benefit plans during the first six months of 2014 and 2013. Future contributions to the plans will be dependent upon many factors, including the performance of existing plan assets and long-term discount rates.

Postemployment Benefits: Postemployment benefits provided to former or inactive employees are recognized when an event occurs. The estimated liability for such benefits was $4.2 million as of both June 30, 2014 and December 31, 2013.

Form 10-Q

9 -- SEGMENT INFORMATION

Summarized financial information concerning our reportable segments for the three and six months ended June 30, 2014 and 2013 is shown in the following table:

Three Months Ended	Reportable Segments Energy Utility	Non-Utility	Corporate & Other (a)	Eliminations & Reconciling Items	Total Consolidated
	(Millions of Dollars)				
June 30, 2014					
Operating Revenues (b)	$1,029.8	$113.4	$0.3	$(99.8)	$1,043.7
Other Operation and Maintenance	$343.6	$5.0	$6.1	$(98.7)	$256.0
Depreciation and Amortization	$84.3	$16.7	$0.4	$—	$101.4
Operating Income (Loss)	$155.2	$91.7	$(6.2)	$—	$240.7
Equity in Earnings of Unconsolidated Affiliates	$17.5	$—	$—	$—	$17.5
Interest Expense, Net	$30.7	$16.2	$12.2	$(0.1)	$59.0
Income Tax Expense (Benefit)	$51.4	$30.2	$(7.3)	$—	$74.3
Net Income (Loss)	$96.3	$45.4	$132.9	$(141.6)	$133.0
Capital Expenditures	$172.6	$4.6	$(0.9)	$—	$176.3
June 30, 2013					
Operating Revenues (b)	$998.0	$113.3	$0.3	$(99.3)	$1,012.3
Other Operation and Maintenance	$357.6	$4.9	$1.2	$(98.3)	$265.4
Depreciation and Amortization	$79.7	$16.8	$0.2	$—	$96.7
Operating Income (Loss)	$138.9	$91.6	$(1.0)	$—	$229.5
Equity in Earnings of Unconsolidated Affiliates	$17.3	$—	$(0.1)	$—	$17.2
Interest Expense, Net	$34.2	$16.5	$12.6	$—	$63.3
Income Tax Expense (Benefit)	$46.4	$30.1	$(6.2)	$—	$70.3
Net Income (Loss)	$80.6	$45.2	$118.9	$(125.7)	$119.0
Capital Expenditures	$167.2	$5.0	$1.5	$—	$173.7

Form 10-Q

Six Months Ended	Reportable Segments Energy Utility	Non-Utility	Corporate & Other (a)	Eliminations & Reconciling Items	Total Consolidated
	(Millions of Dollars)				
June 30, 2014					
Operating Revenues (b)	$2,711.9	$221.7	$0.6	$(195.5)	$2,738.7
Other Operation and Maintenance	$711.2	$6.2	$7.3	$(193.3)	$531.4
Depreciation and Amortization	$167.9	$33.6	$0.5	$—	$202.0
Operating Income (Loss)	$447.9	$181.9	$(7.3)	$—	$622.5
Equity in Earnings of Unconsolidated Affiliates	$34.8	$—	$—	$—	$34.8
Interest Expense, Net	$64.7	$32.5	$24.4	$(0.3)	$121.3
Income Tax Expense (Benefit)	$158.8	$60.2	$(14.4)	$—	$204.6
Net Income (Loss)	$265.7	$89.5	$340.4	$(355.0)	$340.6
Capital Expenditures	$293.3	$9.7	$2.5	$—	$305.5
June 30, 2013					
Operating Revenues (b)	$2,259.5	$223.1	$0.6	$(195.7)	$2,287.5
Other Operation and Maintenance	$738.2	$6.4	$2.2	$(193.3)	$553.5
Depreciation and Amortization	$158.3	$33.5	$0.4	$—	$192.2
Operating Income (Loss)	$369.5	$183.2	$(2.2)	$—	$550.5
Equity in Earnings of Unconsolidated Affiliates	$33.9	$—	$—	$—	$33.9
Interest Expense, Net	$70.1	$33.0	$25.4	$(0.2)	$128.3
Income Tax Expense (Benefit)	$123.8	$60.6	$(13.7)	$—	$170.7
Net Income (Loss)	$218.6	$89.8	$295.5	$(308.3)	$295.6
Capital Expenditures	$298.1	$7.1	$2.1	$—	$307.3

(a) Corporate & Other includes all other non-utility activities, primarily non-utility real estate investment and development by Wispark LLC, 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.

10 -- 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 $194.9 million of required payments over the remaining term of this agreement. We believe that the required lease payments under this contract will continue to be recoverable in rates. Total capacity and lease payments under contracts considered variable interests for the six months ended June 30, 2014 and 2013 were $26.7 million and $25.2 million, respectively. Our maximum exposure to loss is limited to the capacity payments under the contract.

11 -- COMMITMENTS AND CONTINGENCIES

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. We are working with the Wisconsin Department of Natural Resources (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 $19 million to $56 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 June 30, 2014, we have established reserves of $36.9 million 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.

Divested Assets: Pursuant to the sale of the Point Beach Nuclear Power Plant, we agreed to indemnification provisions customary to transactions involving the sale of nuclear assets. We also 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.

12 -- SUPPLEMENTAL CASH FLOW INFORMATION

During the six months ended June 30, 2014, we paid $122.4 million in interest, net of amounts capitalized, and paid $17.6 million in income taxes, net of refunds. During the six months ended June 30, 2013, we paid $127.9 million in interest, net of amounts capitalized, and received $7.6 million in net refunds from income taxes.

As of June 30, 2014 and 2013, the amount of accounts payable related to capital expenditures was $3.2 million and $10.2 million, respectively.

During the six months ended June 30, 2014 and 2013, total amortization of deferred revenue was $27.8 million and $28.8 million, respectively.

During the six months ended June 30, 2014 and 2013, our equity in earnings from ATC was $34.8 million and $33.9 million, respectively. During the six months ended June 30, 2014 and 2013, distributions received from ATC were $28.5 million and $26.8 million, respectively.

Form 10-Q

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

RESULTS OF OPERATIONS -- THREE MONTHS ENDED JUNE 30, 2014

CONSOLIDATED EARNINGS

The following table compares our operating income by business segment and our net income during the second quarter of 2014 with the second quarter of 2013, including favorable (better (B)) or unfavorable (worse (W)) variances:

	Three Months Ended June 30		
	2014	B (W)	2013
	(Millions of Dollars, Except Per Share Amounts)		
Utility Energy Segment	$155.2	$16.3	$138.9
Non-Utility Energy Segment	91.7	0.1	91.6
Corporate and Other	(6.2)	(5.2)	(1.0)
Total Operating Income	240.7	11.2	229.5
Equity in Earnings of Transmission Affiliate	17.5	0.2	17.3
Other Income, net	8.1	2.3	5.8
Interest Expense, net	59.0	4.3	63.3
Income Before Income Taxes	207.3	18.0	189.3
Income Tax Expense	74.3	(4.0)	70.3
Net Income	$133.0	$14.0	$119.0
Diluted Earnings Per Share	$0.58	$0.06	$0.52

UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

Our utility energy segment contributed $155.2 million of operating income during the second quarter of 2014, an increase of $16.3 million, or 11.7%, compared with the second quarter of 2013. The following table summarizes the operating income of this segment between the comparative quarters:

	Three Months Ended June 30		
Utility Energy Segment	2014	B (W)	2013
	(Millions of Dollars)		
Operating Revenues			
Electric	$813.7	$20.5	$793.2
Gas	207.8	10.8	197.0
Other	8.3	0.5	7.8
Total Operating Revenues	1,029.8	31.8	998.0
Operating Expenses			
Fuel and Purchased Power	293.7	(16.3)	277.4
Cost of Gas Sold	125.9	(10.7)	115.2
Other Operation and Maintenance	343.6	14.0	357.6
Depreciation and Amortization	84.3	(4.6)	79.7

Property and Revenue Taxes	30.2	(1.0)	29.2
Total Operating Expenses	877.7	(18.6)	859.1
Treasury Grant	3.1	3.1	—
Operating Income	$155.2	$16.3	$138.9

Form 10-Q

Electric Utility Revenues and Sales

The following table compares electric utility operating revenues and MWh sales by customer class during the second quarter of 2014 with the second quarter of 2013:

	Three Months Ended June 30					
	Electric Revenues			MWh		
Electric Utility Operations	2014	B (W)	2013	2014	B (W)	2013
	(Millions of Dollars)			(Thousands)		
Customer Class						
Residential	$275.0	$(2.2)	$277.2	1,780.7	(70.7)	1,851.4
Small Commercial/Industrial	256.6	0.4	256.2	2,085.2	(54.2)	2,139.4
Large Commercial/Industrial	162.9	(17.0)	179.9	1,854.7	(356.8)	2,211.5
Other - Retail	5.4	0.1	5.3	34.8	(0.7)	35.5
Total Retail	699.9	(18.7)	718.6	5,755.4	(482.4)	6,237.8
Wholesale - Other	32.9	(4.3)	37.2	471.3	(50.6)	521.9
Resale - Utilities	56.5	27.7	28.8	1,483.8	593.0	890.8
Other Operating Revenues	23.0	14.4	8.6	—	—	—
Total	812.3	19.1	793.2	7,710.5	60.0	7,650.5
Electric Customer Choice (a)	1.4	1.4	—	627.5	627.5	—
Total, including electric customer choice	$813.7	$20.5	$793.2			
Weather -- Degree Days (b)						
Heating (941 Normal)				976	(53)	1,029
Cooling (173 Normal)				108	(30)	138

(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.

Our electric utility operating revenues increased by $20.5 million, or 2.6%, when compared to the second quarter of 2013. The most significant factors that caused a change in revenues were:

- A $27.7 million increase in sales for resale resulting from increased sales into the MISO Energy Markets as a result of Michigan's alternative electric supplier program.
- A $22.1 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 - Electric Transmission and Energy Markets - Restructuring in Michigan, for a discussion of the impact of industry restructuring in Michigan on our electric sales.
- A $14.4 million increase in other operating revenues, primarily driven by the recognition of $13.0 million related to revenues under the System Support Resource (SSR) agreement with MISO. See Factors Affecting Results, Liquidity and Capital Resources - Electric Transmission and Energy Markets - Restructuring in Michigan, for a discussion of the SSR payments.
- Wisconsin net retail pricing increases of $9.1 million, which are primarily related to our 2013 Wisconsin Rate Case. For information on the rate order in the 2013 rate case and the 2014 fuel credits, see Factors Affecting Results,

Liquidity and Capital Resources -- Utility Rates and Regulatory Matters.

- Unfavorable weather decreased electric revenues by an estimated $5.3 million.

As measured by cooling degree days, the second quarter of 2014 was 21.7% cooler than the same period in 2013 and 37.6% cooler than normal. We believe the cooler weather was the primary driver of reduced sales to our residential and small commercial/industrial customers. Sales to large commercial/industrial customers decreased by 16.1%, primarily because of the loss of the two iron ore mines in Michigan as retail electric customers. If the sales to the mines in the second quarter of 2013 are excluded, sales to our large commercial/industrial customers decreased 0.2%.

Form 10-Q

Fuel and Purchased Power

Our fuel and purchased power costs increased by $16.3 million, or 5.9%, when compared to the second quarter of 2013. This increase was primarily caused by higher generating costs driven by an increase in natural gas prices as compared to the second quarter of 2013.

Gas Utility Revenues, Gross Margin and Therm Deliveries

A comparison follows of gas utility operating revenues, gross margin and gas deliveries during the second quarter of 2014 with the second quarter of 2013. 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. Between the comparative periods, total gas operating revenues increased by $10.8 million, or 5.5%. Cost of gas sold increased by $10.7 million, or 9.3%, because of an increase in the average cost of delivered gas.

	Three Months Ended June 30		
	2014	B (W)	2013
	(Millions of Dollars)		
Gas Operating Revenues	$207.8	$10.8	$197.0
Cost of Gas Sold	125.9	(10.7)	115.2
Gross Margin	$81.9	$0.1	$81.8

The following table compares gas utility gross margin and natural gas therm deliveries by customer class during the second quarter of 2014 with the second quarter of 2013:

	Three Months Ended June 30					
	Gross Margin			Therms		
Gas Utility Operations	2014	B (W)	2013	2014	B (W)	2013
	(Millions of Dollars)			(Millions)		
Customer Class						
Residential	$51.7	$0.7	$51.0	120.8	2.5	118.3
Commercial/Industrial	15.8	(0.8)	16.6	73.5	(6.0)	79.5
Interruptible	0.3	(0.1)	0.4	3.3	(0.3)	3.6
Total Retail	67.8	(0.2)	68.0	197.6	(3.8)	201.4
Transported Gas	11.9	0.3	11.6	240.3	15.2	225.1
Other Operating	2.2	—	2.2	—	—	—
Total	$81.9	$0.1	$81.8	437.9	11.4	426.5
Weather -- Degree Days (a)						
Heating (941 Normal)				976	(53)	1,029

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

Our gas margin increased by $0.1 million, or approximately 0.1%, when compared to the second quarter of 2013. The unfavorable impact of weather was offset by favorable impacts tied to the economy and customer growth. As measured by heating degree days, the second quarter of 2014 was 5.2% warmer than the same period in 2013 and 3.7% cooler than normal.

Other Operation and Maintenance Expense

Our other operation and maintenance expense decreased by $14.0 million, or approximately 3.9%, when compared to the second quarter of 2013. This decrease was primarily driven by lower benefit costs.

Depreciation and Amortization Expense

Our depreciation and amortization expense increased by $4.6 million, or approximately 5.8%, when compared to the second quarter of 2013 primarily because of an overall increase in utility plant in service. Our new biomass plant went into service in November 2013.

Treasury Grant

In December 2013, we filed an application with the United States Treasury for a Section 1603 Renewable Energy Treasury Grant (Treasury Grant) related to the construction of our biomass facility. 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. We began to record grant income when the biomass facility was placed into service in the fourth quarter of 2013.

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 will be returned to customers in future rate proceedings.

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 are recognizing Treasury Grant income to match the bill credits related to the grant that our Wisconsin retail electric customers are receiving.

NON-UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

Our non-utility energy segment consists primarily of our PTF units (Port Washington Generating Station Unit 1 (PWGS 1), Port Washington Generating Station Unit 2 (PWGS 2), Oak Creek expansion Unit 1 (OC 1) and Oak Creek expansion Unit 2 (OC 2)).

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

	Three Months Ended June 30		
	2014	B (W)	2013
	(Millions of Dollars)		
Operating Revenues	$113.4	$0.1	$113.3
Operation and Maintenance Expense	5.0	(0.1)	4.9
Depreciation Expense	16.7	0.1	16.8
Operating Income	$91.7	$0.1	$91.6

CORPORATE AND OTHER CONTRIBUTION TO OPERATING INCOME

Corporate and other affiliates had an operating loss of $6.2 million for the three months ended June 30, 2014 as compared to a loss of $1.0 million for the same period in 2013. The increase in operating loss is primarily attributable to approximately $5.1 million of Acquisition related costs.

Form 10-Q

CONSOLIDATED OTHER INCOME, NET

	Three Months Ended June 30		
	2014	B (W)	2013
	(Millions of Dollars)		
AFUDC - Equity	$1.3	$(3.3)	$4.6
Gain on Property Sales	5.6	$5.3	0.3
Other, net	1.2	0.3	0.9
Other Income, net	$8.1	$2.3	$5.8

Other income, net increased by $2.3 million, or approximately 39.7%, when compared to the second quarter of 2013. The decrease in AFUDC - Equity is primarily related to the biomass plant going into service in November 2013.

CONSOLIDATED INTEREST EXPENSE, NET

	Three Months Ended June 30		
	2014	B (W)	2013
	(Millions of Dollars)		
Gross Interest Costs	$59.7	$5.9	$65.6
Less: Capitalized Interest	0.7	(1.6)	2.3
Interest Expense, net	$59.0	$4.3	$63.3

Our gross interest costs decreased by $5.9 million, or approximately 9.0%, when compared to the second quarter of 2013 primarily due to lower debt levels and lower average interest rates. Our capitalized interest decreased by $1.6 million primarily because of lower construction work in progress as the biomass plant went into service in November 2013. As a result, our net interest expense decreased by $4.3 million, or 6.8%, as compared to the second quarter of 2013.

CONSOLIDATED INCOME TAX EXPENSE

For the second quarter of 2014, our effective tax rate applicable to continuing operations was 35.8% compared to 37.1% for the second quarter of 2013. This decrease in our effective tax rate was primarily due to the favorable recognition of a prior year federal tax position partially offset by reduced tax benefits associated with Treasury Grant income and decreased AFUDC - Equity. For additional information, see Note G -- Income Taxes in our 2013 Annual Report on Form 10-K.

Form 10-Q

RESULTS OF OPERATIONS -- SIX MONTHS ENDED JUNE 30, 2014

CONSOLIDATED EARNINGS

The following table compares our operating income by business segment and our net income during the first six months of 2014 with the first six months of 2013, including favorable (better (B)) or unfavorable (worse (W)) variances:

	Six Months Ended June 30		
	2014	B (W)	2013
	(Millions of Dollars, Except Per Share Amounts)		
Utility Energy Segment	$447.9	$78.4	$369.5
Non-Utility Energy Segment	181.9	(1.3)	183.2
Corporate and Other	(7.3)	(5.1)	(2.2)
Total Operating Income	622.5	72.0	550.5
Equity in Earnings of Transmission Affiliate	34.8	0.9	33.9
Other Income, net	9.2	(1.0)	10.2
Interest Expense, net	121.3	7.0	128.3
Income Before Income Taxes	545.2	78.9	466.3
Income Tax Expense	204.6	(33.9)	170.7
Net Income	$340.6	$45.0	$295.6
Diluted Earnings Per Share	$1.50	$0.22	$1.28

UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

Our utility energy segment contributed $447.9 million of operating income during the first six months of 2014, an increase of $78.4 million, or 21.2%, compared with the first six months of 2013. The following table summarizes the operating income of this segment between the comparative periods:

	Six Months Ended June 30		
Utility Energy Segment	2014	B (W)	2013
	(Millions of Dollars)		
Operating Revenues			
Electric	$1,699.5	$94.0	$1,605.5
Gas	985.8	354.8	631.0
Other	26.6	3.6	23.0
Total Operating Revenues	2,711.9	452.4	2,259.5
Operating Expenses			
Fuel and Purchased Power	613.6	(63.9)	549.7
Cost of Gas Sold	717.4	(332.1)	385.3
Other Operation and Maintenance	711.2	27.0	738.2
Depreciation and Amortization	167.9	(9.6)	158.3
Property and Revenue Taxes	60.5	(2.0)	58.5
Total Operating Expenses	2,270.6	(380.6)	1,890.0
Treasury Grant	6.6	6.6	—
Operating Income	$447.9	$78.4	$369.5

Form 10-Q

Electric Utility Revenues and Sales

The following table compares electric utility operating revenues and MWh sales by customer class during the first six months of 2014 with the first six months of 2013:

	Six Months Ended June 30					
	Electric Revenues			MWh		
Electric Utility Operations	2014	B (W)	2013	2014	B (W)	2013
	(Millions of Dollars)			(Thousands)		
Customer Class						
Residential	$594.2	$13.8	$580.4	3,943.3	47.4	3,895.9
Small Commercial/Industrial	516.6	6.5	510.1	4,338.4	19.9	4,318.5
Large Commercial/Industrial	314.1	(52.1)	366.2	3,647.6	(911.7)	4,559.3
Other - Retail	11.5	—	11.5	74.2	(0.8)	75.0
Total Retail	1,436.4	(31.8)	1,468.2	12,003.5	(845.2)	12,848.7
Wholesale - Other	73.7	(3.0)	76.7	1,076.1	37.2	1,038.9
Resale - Utilities	148.3	102.2	46.1	2,927.3	1,476.6	1,450.7
Other Operating Revenues	38.3	23.8	14.5	—	—	—
Total	1,696.7	91.2	1,605.5	16,006.9	668.6	15,338.3
Electric Customer Choice (a)	2.8	2.8	—	1,228.7	1,228.7	—
Total, including electric customer choice	$1,699.5	$94.0	$1,605.5			
Weather -- Degree Days (b)						
Heating (4,199 Normal)				5,009	509	4,500
Cooling (174 Normal)				108	(30)	138

(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.

Our electric utility operating revenues increased by $94.0 million, or 5.9%, when compared to the first six months of 2013. The most significant factors that caused a change in revenues were:

- A $102.2 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.
- A $55.6 million decrease in large commercial/industrial sales because of the two iron ore mines switching to an alternative electric supplier in September 2013.
- A $23.8 million increase in other operating revenues, primarily driven by the recognition of $21.8 million related to revenues under the SSR agreement with MISO.
- Wisconsin net retail pricing increases of $18.2 million, which are primarily related to our 2013 Wisconsin Rate Case.
- Favorable winter weather increased electric revenues by an estimated $12.7 million.

As measured by heating degree days, the first six months of 2014 were 11.3% colder than the same period in 2013 and 19.3% colder than normal. This favorable impact of the winter weather was partially offset by mild weather in the second quarter that reduced the cooling load. Cooling degree days decreased 21.7% during the first six months of

2014 as compared to the same period in 2013. Residential sales increased by 1.2%, primarily because of weather. Sales to large commercial/industrial customers decreased by 20.0%, 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 0.4% compared to 2013.

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Fuel and Purchased Power

Our fuel and purchased power costs increased by $63.9 million, or 11.6%, when compared to the first six months of 2013. This increase was primarily caused by a 4.4% increase in total MWh sales and higher generating costs driven by an increase in natural gas prices.

Gas Utility Revenues, Gross Margin and Therm Deliveries

A comparison follows of gas utility operating revenues, gross margin and gas deliveries during the first six months of 2014 with the first six months of 2013. 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. Between the comparative periods, total gas operating revenues increased by $354.8 million, or 56.2%, and cost of gas sold increased by $332.1 million, or 86.2%, due to colder weather and an increase in the commodity cost of natural gas.

	Six Months Ended June 30		
	2014	B (W)	2013
	(Millions of Dollars)		
Gas Operating Revenues	$985.8	$354.8	$631.0
Cost of Gas Sold	717.4	(332.1)	385.3
Gross Margin	$268.4	$22.7	$245.7

The following table compares gas utility gross margin and natural gas therm deliveries by customer class during the first six months of 2014 with the first six months of 2013:

	Six Months Ended June 30					
	Gross Margin			Therms		
Gas Utility Operations	2014	B (W)	2013	2014	B (W)	2013
	(Millions of Dollars)			(Millions)		
Customer Class						
Residential	$171.3	$12.7	$158.6	586.4	65.8	520.6
Commercial/Industrial	63.8	7.7	56.1	347.0	48.1	298.9
Interruptible	1.0	—	1.0	10.5	0.4	10.1
Total Retail	236.1	20.4	215.7	943.9	114.3	829.6
Transported Gas	28.1	1.6	26.5	552.6	10.9	541.7
Other	4.2	0.7	3.5	—	—	—
Total	$268.4	$22.7	$245.7	1,496.5	125.2	1,371.3
Weather -- Degree Days (a)						
Heating (4,199 Normal)				5,009	509	4,500

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

Our gas margin increased by $22.7 million, or approximately 9.2%, when compared to the first six months of 2013. This increase primarily relates to an increase in sales volumes as a result of colder weather during the first six months of 2013 that increased heating loads. We estimate that weather increased gas margins by approximately $16.7 million. As measured by heating degree days, the first six months of 2014 were 11.3% colder than the same period in 2013 and

19.3% colder than normal.

Other Operation and Maintenance Expense

Our other operation and maintenance expense decreased by $27.0 million, or approximately 3.7%, when compared to the first six months of 2013. This decrease was primarily driven by lower benefit costs.

Form 10-Q

Depreciation and Amortization Expense

Our depreciation and amortization expense increased by $9.6 million, or approximately 6.1%, when compared to the first six months of 2013 primarily because of an overall increase in utility plant in service. Our new biomass plant went into service in November 2013.

Treasury Grant

For a discussion of the impact of the Treasury Grant on our results of operations, see Results of Operations -- Three Months Ended June 30, 2014 -- Treasury Grant.

NON-UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

This segment reflects the lease revenues associated with PWGS 1, PWGS 2, OC 1 and OC 2, as well as the depreciation expense. The operating and maintenance costs associated with the plants are the responsibility of Wisconsin Electric and are recorded in the utility segment.

	Six Months Ended June 30		
	2014	B (W)	2013
	(Millions of Dollars)		
Operating Revenues	$221.7	$(1.4)	$223.1
Operation and Maintenance Expense	6.2	0.2	6.4
Depreciation Expense	33.6	(0.1)	33.5
Operating Income	$181.9	$(1.3)	$183.2

Non-utility energy segment operating income decreased by $1.3 million, or approximately 0.7%, when compared to the first six months of 2013. The decrease in operating revenues is primarily related to the one-time entries during 2013 to recognize final approved construction costs for the Oak Creek expansion as part of the 2013 Wisconsin Rate Case.

CORPORATE AND OTHER CONTRIBUTION TO OPERATING INCOME

Corporate and other affiliates had an operating loss of $7.3 million for the six months ended June 30, 2014 as compared to a loss of $2.2 million for the same period in 2013. The increase in operating loss is primarily attributable to approximately $5.1 million of Acquisition related costs.

CONSOLIDATED OTHER INCOME, NET

	Six Months Ended June 30		
	2014	B (W)	2013
	(Millions of Dollars)		
AFUDC - Equity	$2.3	$(6.6)	$8.9
Gain on Property Sales	5.6	5.1	0.5
Other, net	1.3	0.5	0.8
Other Income, net	$9.2	$(1.0)	$10.2

Other income, net decreased by $1.0 million, or approximately 9.8%, when compared to the first six months of 2013. The decrease in AFUDC - Equity is primarily related to the biomass plant going into service in November 2013.

Form 10-Q

CONSOLIDATED INTEREST EXPENSE, NET

	Six Months Ended June 30		
	2014	B (W)	2013
	(Millions of Dollars)		
Gross Interest Costs	$122.6	$10.2	$132.8
Less: Capitalized Interest	1.3	(3.2)	4.5
Interest Expense, net	$121.3	$7.0	$128.3

Our gross interest costs decreased by $10.2 million, or approximately 7.7%, when compared to the first six months of 2013 primarily due to lower debt levels and lower average interest rates. Our capitalized interest decreased by $3.2 million primarily because of lower construction work in progress as the biomass plant went into service in November 2013. As a result, our net interest expense decreased by $7.0 million, or 5.5%, as compared to the first six months of 2013.

CONSOLIDATED INCOME TAX EXPENSE

For the first six months of 2014, our effective tax rate applicable to continuing operations was 37.5% compared to 36.6% for the first six months of 2013. This increase in our effective tax rate was primarily due to reduced tax benefits associated with Treasury Grant income and decreased AFUDC - Equity. For additional information, see Note G -- Income Taxes in our 2013 Annual Report on Form 10-K. We expect our 2014 annual effective tax rate to be between 37.5% and 38.5%.

LIQUIDITY AND CAPITAL RESOURCES

CASH FLOWS

The following summarizes our cash flows during the six months ended June 30:

	2014	2013
	(Millions of Dollars)	
Cash Provided by (Used in)		
Operating Activities	$721.3	$681.5
Investing Activities	$(312.9)	$(336.6)
Financing Activities	$(401.0)	$(359.5)

Operating Activities

Cash provided by operating activities increased by $39.8 million during the first six months of 2014 as compared to the same period in 2013. The increase is primarily because of $76.2 million of proceeds related to the Treasury Grant and higher net income. These items were partially offset by higher working capital requirements.

Investing Activities

Cash used in investing activities decreased by $23.7 million during the first six months of 2014 as compared to the same period in 2013. Our capital expenditures decreased by $1.8 million during the first six months of 2014 as compared to the same period in 2013, primarily because of the completion of the biomass plant in November 2013.

Financing Activities

Cash used in financing activities increased by $41.5 million during the first six months of 2014 as compared to the same period in 2013. During the first six months of 2014, we repaid $68.6 million more short-term debt as compared to the first six months of 2013 because of improved cash flows from operating activities. Our quarterly common stock dividend increased by 12.5% and 2.0% in the third quarter of 2013 and first quarter of 2014, respectively, resulting in an increase of dividends paid on common stock of $20.4 million in the first six months of 2014 as compared to the same period last year. These factors were partially offset by a decrease in repurchases of common stock. During the first six months of 2014, we repurchased $57.3 million of common stock as compared to $135.7 million during the same period in 2013. See Note 4 -- Common Equity for additional information on share repurchases.

CAPITAL RESOURCES AND REQUIREMENTS

Liquidity

We anticipate meeting our capital requirements during the remainder of 2014 and beyond primarily through internally generated funds and short-term borrowings, supplemented by the issuance of intermediate or long-term debt securities, depending on market conditions and other factors.

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

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

As of June 30, 2014, we had approximately $1.2 billion of available, undrawn lines under our bank back-up credit facilities, and approximately $410.1 million of commercial paper outstanding on a consolidated basis that was supported by the available lines of credit. During the first six months of 2014, our maximum commercial paper outstanding was $721.4 million with a weighted-average interest rate of 0.18%.

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 June 30, 2014:

Company	Total Facility	Letters of Credit	Credit Available	Facility Expiration
	(Millions of Dollars)			
Wisconsin Energy	$400.0	$0.1	$399.9	December 2017
Wisconsin Electric	$500.0	$5.1	$494.9	December 2017
Wisconsin Gas	$350.0	$—	$350.0	December 2017

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

The following table shows our capitalization structure as of June 30, 2014, as well as an adjusted capitalization structure that we believe is consistent with the manner in which the rating agencies currently view Wisconsin Energy's 2007 Series A Junior Subordinated notes due 2067 (Junior Notes):

Capitalization Structure	Actual	Adjusted
	(Millions of Dollars)	
Common Equity	$4,367.1	$4,617.1
Preferred Stock of Subsidiary	30.4	30.4
Long-Term Debt (including current maturities)	4,632.6	4,382.6
Short-Term Debt	410.1	410.1
Total Capitalization	$9,440.2	$9,440.2
Total Debt	$5,042.7	$4,792.7
Ratio of Debt to Total Capitalization	53.4 %	50.8 %

Included in Long-Term Debt on our Consolidated Condensed Balance Sheet as of June 30, 2014 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.

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 June 30, 2014, the repurchased bonds were still outstanding, but were not reported as long-term debt because they are held by Wisconsin Electric. Depending on market conditions and other factors, Wisconsin Electric may change the method used to determine the interest rate on the bonds and have them remarketed to third parties.

Credit Rating Risk

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 June 2014, Standard and Poor's Ratings Services (S&P) affirmed the ratings of Wisconsin Energy, Wisconsin Electric, Wisconsin Gas and Wisconsin Energy Capital Corporation (WECC). 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.

In June 2014, Fitch Ratings placed the ratings of Wisconsin Energy and WECC on Rating Watch Negative. This action had no impact on the ratings and outlooks of Wisconsin Electric, Wisconsin Gas and Elm Road Generating

Station Supercritical (ERGSS).

In June 2014, Moody's Investors Service (Moody's) affirmed the ratings of Wisconsin Energy, Wisconsin Electric, Wisconsin Gas, ERGSS and WECC. Moody's affirmed the stable ratings outlook for Wisconsin Electric, Wisconsin Gas and ERGSS, and revised the ratings outlook for Wisconsin Energy and WECC from stable to negative.

The change in outlooks for Wisconsin Energy and WECC relate to the announcement that we are acquiring Integrys.

Form 10-Q

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.

See Capital Resources and Requirements -- Credit Rating Risk in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations in our 2013 Annual Report on Form 10-K for additional information related to our credit rating risk.

Capital Requirements

Acquisition of Integrys: On June 22, 2014, we entered into an agreement to acquire Integrys for approximately $5.8 billion. Integrys shareholders will receive 1.128 shares of Wisconsin Energy common stock and $18.58 in cash per share of Integrys common stock. The Acquisition is scheduled to close in the second half of 2015, and is subject to the receipt of various approvals. We expect to finance the Acquisition through the issuance of approximately $1.5 billion of debt at the holding company and approximately 91 million shares of Wisconsin Energy common stock.

Capital Expenditures: Capital requirements during the remainder of 2014 are expected to be principally for capital expenditures in our utility operations relating to our electric and gas distribution systems. We estimate that we will spend approximately $711.0 million on consolidated capital expenditures during 2014.

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 June 30, 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 Acquisition, the Board of Directors terminated this share repurchase program.

In addition, on January 16, 2014, our Board of Directors increased our quarterly common stock dividend to $0.39 per share, up approximately 2.0%, from $0.3825 per share, effective with the first quarter 2014 dividend payment. This equates to an annual dividend of $1.56 per share.

Prior to closing the Acquisition, we plan to continue our current dividend policy, which would provide for a 7-8% annual increase in the dividend. At closing, we expect a further dividend increase for our shareholders to reflect the dividend policy of the combined company. In future years after closing, the projected payout target for the combined company will be 65-70 percent of earnings.

Off-Balance Sheet Arrangements: We are a party to various financial instruments with off-balance sheet risk as a part of our normal course of business, including financial guarantees and letters of credit which support construction projects, commodity contracts and other payment obligations. We believe that these agreements do not have, and are not reasonably likely to have, a current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to our investors. For further information, see Note 10 -- Variable Interest Entities in the Notes to Consolidated Condensed Financial Statements in this report.

Contractual Obligations/Commercial Commitments: Our total contractual obligations and other commercial commitments were approximately $21.9 billion as of June 30, 2014 compared with $22.2 billion as of December 31, 2013.

FACTORS AFFECTING RESULTS, LIQUIDITY AND CAPITAL RESOURCES

The following is a discussion of certain factors that may affect our results of operations, liquidity and capital resources. The following discussion should be read together with the information under the heading "Factors Affecting Results, Liquidity and Capital Resources" in Item 7 of our 2013 Annual Report on Form 10-K, which provides a more complete discussion of factors affecting us, including market risks and other significant risks, our PTF strategy, utility rates and regulatory matters, electric system reliability, environmental matters, legal matters, industry restructuring and competition and other matters.

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.

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

We 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. Bechtel and Wisconsin Electric resolved an additional warranty claim in April 2014 which also did not have a material impact. The parties continue to work through one remaining item.

See Factors Affecting Results, Liquidity and Capital Resources -- Power the Future in Item 7 of our 2013 Annual Report on Form 10-K for additional information on PTF.

UTILITY RATES AND REGULATORY MATTERS

2015 Wisconsin Rate Case: On May 30, 2014, Wisconsin Electric and Wisconsin Gas applied to the PSCW for a biennial review of costs and rates.

Wisconsin Electric and Wisconsin Gas engaged in settlement discussions related to this review, facilitated by PSCW Staff, with the Citizens Utility Board, the Wisconsin Industrial Energy Group and the Wisconsin Paper Council. As a result of these discussions, Wisconsin Electric, Wisconsin Gas and the three customer groups have agreed on the following:

- Wisconsin Electric is requesting a rate increase of $41.5 million (1.43%), excluding fuel, for its Wisconsin retail electric customers in 2015; or $52.3 million (1.81%) when including estimated fuel costs for 2015. This increase reflects an offset of $26.2 million (0.91%) related to bill credits. Other than the expiration of the bill credits, no adjustment to electric base rates would be made in 2016.
- Wisconsin Electric is requesting a rate decrease of $10.7 million (2.39%) for its natural gas customers in 2015, with no rate adjustment in 2016.
- Wisconsin Electric is requesting rate increases in 2015 of $0.5 million (2.10%) and $0.8 million (4.56%) for its downtown Milwaukee and Milwaukee County steam customers, respectively, with no rate adjustments in 2016.
- Wisconsin Gas is requesting rate increases of $21.1 million (3.27%) and $21.4 million (3.32%) in 2015 and 2016, respectively, for its natural gas customers.

In addition, the parties have agreed that the authorized return on equity for Wisconsin Electric and Wisconsin Gas should be set at 10.2% and 10.3%, respectively. The agreement between the parties calls for the Wisconsin Gas financial common equity component to increase to an average of 49.5% compared to the current 47.5%, while Wisconsin Electric's equity component will remain the same.

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

- A net bill increase related to non-fuel costs for Wisconsin Electric's Wisconsin retail electric customers of approximately $70 million (2.6%) for 2013. This amount reflects an offset of approximately $63 million (2.3%) of bill credits related to the proceeds of the Treasury Grant, including related tax benefits. Absent this offset, the retail electric rate increase for non-fuel costs was approximately $133 million (4.8%) for 2013.

- An electric rate increase for Wisconsin Electric's Wisconsin electric customers of approximately $28 million (1.0%) for 2014, and a $45 million (1.6%) reduction in bill credits.
- Recovery of a forecasted increase in fuel costs of approximately $44 million (1.6%) for 2013.
- A rate decrease of approximately $8 million (1.9%) for Wisconsin Electric's natural gas customers for 2013, with no rate adjustment in 2014. The new Wisconsin Electric rates reflect a $6.4 million reduction in bad debt expense.
- A rate decrease of approximately $34 million (5.5%) for Wisconsin Gas' natural gas customers for 2013, with no rate adjustment in 2014. The new Wisconsin Gas rates reflect a $43.8 million reduction in bad debt expense.
- An increase of approximately $1.3 million (6.0%) for Wisconsin Electric's downtown Milwaukee steam utility customers for 2013 and another $1.3 million (6.0%) in 2014.
- An increase of approximately $1 million (7.0%) in 2013 and $1 million (6.0%) in 2014 for Wisconsin Electric's Milwaukee County steam utility customers.

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

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

Gas Cost Recovery Mechanism: Our natural gas operations operate under Gas Cost Recovery Mechanisms (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 recovered from our customers.

Renewable Energy Portfolio: Wisconsin Electric 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 will also support Domtar's sustainable papermaking operations. The final cost of completing this project was $269.0 million, excluding AFUDC.

Western Gas Lateral: We are projecting the need for additional capacity for our natural gas distribution network in the western part of Wisconsin to address reliability and meet customer demand. We filed an application with the PSCW seeking approval to construct a new natural gas lateral in March 2013. We received the final written order approving the project on July 18, 2014. The anticipated cost of the initial phase of this project is approximately $175 million to $185 million, excluding AFUDC. We are targeting completion of this project in late 2015.

See Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters in Item 7 of our 2013 Annual Report on Form 10-K for additional information regarding our utility rates and other regulatory matters.

ELECTRIC TRANSMISSION AND ENERGY MARKETS

As part of MISO, a market-based platform was developed for valuing transmission congestion premised upon the Locational Marginal Price (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 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.

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

The mines, which we served on an interruptible tariff rate, switched to an alternative electric supplier in September 2013. In addition, other smaller retail customers have switched to an alternative electric supplier.

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

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

In addition, we have been evaluating options for the long-term future of PIPP. As part of that process, we issued a request for proposals regarding the potential purchase of PIPP in January 2014. We did not receive any proposals by the March 3, 2014 deadline. Based upon our evaluation and the lack of interest to purchase the plant, on April 15, 2014, we filed a request with MISO to retire PIPP effective October 15, 2014. On May 28, 2014, MISO informed us that they had determined the operation of all five units at PIPP is necessary for reliability purposes; therefore, the units will continue to be designated as SSR units, unless an alternative solution is identified through the stakeholder planning process. We expect that MISO will again find that there are limited alternatives to continued operation of the plant at this point. We plan to enter into a new SSR agreement with MISO, effective October 15, 2014, that would be expected to cover operations for one year. The costs to comply with the Mercury and Air Toxic Standards (MATS) are expected to be included for recovery in the new SSR agreement. For additional information related to MATS, see Environmental Matters -- Air Quality -- Mercury and Other Hazardous Air Pollutants later in this report.

See Factors Affecting Results, Liquidity and Capital Resources - Industry Restructuring and Competition in Item 7 of our 2013 Form 10-K for additional information regarding the impact of industry restructuring in Michigan, as well as information regarding other restructuring matters and MISO.

ENVIRONMENTAL MATTERS

Air Quality

National Ambient Air Quality Standards

8-hour Ozone Standards: In April 2004, the United States Environmental Protection Agency (EPA) designated 10 counties in southeastern Wisconsin as non-attainment areas for the 1997 8-hour ozone ambient air quality standard. The EPA has since redesignated all of these counties to attainment. In 2008, the EPA issued an additional, more stringent 8-hour ozone standard, and made final attainment designations for this revised standard in 2012. In April 2012 and May 2012, the EPA designated Sheboygan County and the eastern portion of Kenosha County, respectively, as 2008 8-hour ozone standard non-attainment areas. The net result of all of these actions is that construction permitting for all of our Wisconsin power plants, except the Pleasant Prairie Power Plant, is expected to be subject to less stringent permitting requirements. In addition, modifications to these facilities should no longer be required to obtain emission offsets. 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 January 2010, the EPA announced its decision to further lower the 2008 8-hour ozone standard. However, in September 2011, President Obama requested the EPA to delay the reconsideration of the 8-hour ozone standard. In January 2014, environmental groups petitioned the U.S. District Court for the Northern District of California to order the EPA to propose a new ozone standard by the end of 2014 and to finalize the standard by October 2015. We expect the EPA to lower the 8-hour ozone standard from its current level. 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.

Sulfur Dioxide Standard: In June 2010, the EPA issued new hourly Sulfur Dioxide (SO_2) National Ambient Air Quality Standards (NAAQS) that became effective in August 2010. This standard represented a significant change from the previous SO_2 standard. The implementation guidance for the new standard, among other things, required attainment designations to be based on modeling rather than monitoring. Traditionally, attainment designations were based on monitored data. The EPA has since advised that it is revisiting this implementation guidance. In addition, various parties have submitted judicial and administrative challenges to this rule, and litigation is pending in the U.S. Court of Appeals for the D.C. Circuit challenging, among other things, the stringency of the standards and the EPA's plans to require attainment designations to be based on modeling.

The EPA issued two technical assistance documents for comment in 2013, and on May 13, 2014, issued the proposed Data Requirements Rule for the 1-Hour SO_2 Primary NAAQS that will establish requirements for characterizing SO_2 air quality in priority areas (areas with large sources of SO_2 or large populations). The proposed rule describes the EPA's plans for using a combination of monitoring and modeling to make designations for areas that have not yet been designated attainment, non-attainment or unclassifiable for the 1-Hour SO_2 standard. As part of the comments we filed with the EPA in July 2014, we proposed a special reliability exclusion for PIPP which would recognize the planned facility retirement, 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. The way in which state agencies employ this discretion will affect each source’s actual compliance obligations. In addition, the extent to which EPA exerts its “oversight” authority will also affect the final stringency of the rule and its requirements. Affected facilities would have the option of modeling or monitoring to show attainment (subject to state approval for this selection). If an affected facility is unable to show modeled attainment, then the facility would have to make emission reductions by 2017 in order to avoid a non-attainment designation. 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. If the source does not make reductions by 2017 and was classified as non-attainment, then it would have to make emission reductions by 2023. Alternatively, if a source opted out of modeling and instead installed monitoring, and subsequently monitored non-attainment, then it would face a 2026 compliance date. The rule does not allow any kind of facility averaging or trading program.

We do not believe that we will need to make any significant additional expenditures at the majority of our generating units because of prior investments in pollution control equipment. We are evaluating the proposed rule to determine if additional controls will be required at PIPP or at our smaller generating units.

Mercury and Other Hazardous Air Pollutants: In December 2011, the EPA issued the final MATS rule, which imposes stringent limitations on numerous hazardous air pollutants, including mercury, from coal and oil-fired electric generating units. We currently anticipate that only PIPP will require modifications, and are planning for the addition of dry sorbent injection systems 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).

Cross-State Air Pollution Rule: In August 2011, the EPA issued the Cross-State Air Pollution Rule (CSAPR), formerly known as the Clean Air Transport Rule. This rule was proposed in 2010 to replace the Clean Air Interstate Rule (CAIR), which had been remanded to the EPA in 2008. The stated purpose of the CSAPR is to limit the interstate transport of emissions of Nitrogen Oxide (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. On April 29, 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. In light of this decision and further proceedings by the appellate court, we are re-evaluating the rule and availability of allowances in Michigan 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.

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 fine particulate matter or compounds that contribute to fine particulate formation, NO_X, SO_2 and ammonia.

In June 2012, the EPA promulgated a Federal Implementation Plan that approves reliance on the CSAPR to satisfy electric generating unit BART requirements for NO_X and SO_2. In December 2012, the EPA approved the remainder of Michigan's regional haze State Implementation Plan (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.

The U.S. Supreme Court decision on April 29, 2014 that upheld the CSAPR allows for the final regional haze rulemaking activities and requirements for NO_X and SO_2 to proceed. We believe we will be well positioned to meet the Clean Air Visibility rule based on air quality control system additions that are already in place or planned for our generating facilities.

Valley Power Plant Conversion: In August 2012, we announced plans to convert the fuel source for Valley Power Plant (VAPP) from coal to natural gas. We currently expect the cost of this conversion to be between $65 million and $70 million, excluding AFUDC, and anticipate that the conversion will be completed by the end of 2015. We filed for a Certificate of Authority from the PSCW in April 2013, and received final written approval in March 2014. Construction is underway with the conversion of two boilers scheduled for completion in 2014, and the remaining two boilers scheduled for completion in 2015.

Greenhouse Gas (GHG) Regulations: The EPA issued proposed guidelines relating to GHG emissions from existing generating units on June 18, 2014, and has announced plans to issue final rules by June 2015. The EPA also published proposed performance standards for modified and reconstructed generating units. The proposed guidelines seek to attain state-specific GHG rate reductions by 2030, and requires 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. 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, in Utility Air Regulatory Group v. EPA, 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 Best Available Control Technology for facilities already subject to PSD or Title V permitting requirements for other pollutants. We are evaluating the potential impact of this decision.

Water Quality

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

The EPA proposed a new Phase II rule in 2011, and issued the final Phase II rule on May 16, 2014. The new rule will apply 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 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 WDNR and MDEQ, subject to EPA oversight, when facility permits are reissued. Based upon our preliminary 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. We plan to install fish protection screens at VAPP that we expect 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. Because the entrainment reduction standard is a site-specific determination, we cannot yet determine what, if any, intake structure or operational modifications will be required to meet the new requirements.

See Factors Affecting Results, Liquidity and Capital Resources -- Environmental Matters in Item 7 of our 2013 Annual Report on Form 10-K for additional information regarding environmental matters affecting our operations.

OTHER MATTERS

Oak Creek Expansion Fuel Flexibility Project: The Oak Creek expansion units were designed and permitted to use bituminous coal from the Eastern United States. Market forces have resulted in a significant price differential between bituminous and sub-bituminous coals. We received a new air construction permit from the WDNR to modify the Oak Creek expansion units for potential future use of sub-bituminous coal. In 2013, we began testing various combinations of sub-bituminous coal and bituminous coal to identify any equipment limitations, and making equipment modifications to the units. In February 2013, the Sierra Club and the Midwest Environmental Defense Center filed a petition for a contested case hearing with the WDNR to challenge the issuance of the air construction permit. The WDNR has granted that petition, but a hearing has not yet been scheduled.

Paris Generating Station Units 1 and 4 Temporary Outage: Between 2000 and 2002, we replaced the blades on the four Paris Generating Station (PSGS) combustion turbine generators with blades that were approximately 7% more efficient. Although the work was performed as routine maintenance that we did not believe required a construction permit at the time and the plant has not been operated to use the potential additional capacity, the WDNR has indicated that it now considers this maintenance to be a modification requiring a construction permit. The WDNR issued a Notice of Violation (NOV) to Wisconsin Electric in January 2013 alleging violations of the new source review rules and certain Wisconsin environmental rules. At the same time, the WDNR also issued an administrative order that prohibits us from operating PSGS Units 1 and 4 until the earlier of: (1) Units 1 and 4 achieve the applicable NO_X emission rates; (2) the Wisconsin regulations are revised so that Units 1 and 4 can achieve the emission limits or are no longer subject to the limits; (3) the alleged modification is resolved through a consent decree; or (4) a court decides that the blade replacement project was not a major modification. We are presently evaluating alternative approaches to return these peaking units to service, and expect Units 1 and 4 to remain out of service until at least the end of this summer. In December 2013, Act 91 was signed into law in Wisconsin, creating a process by which the EPA and WDNR may revise the regulations applicable to Units 1 and 4 and allow those units to restart.

In February 2013, the Sierra Club filed for a contested case hearing with the WDNR in connection with the administrative order. The WDNR has granted that petition, but a hearing has not yet been scheduled. In addition, in May 2013, the WDNR referred the matter to the Wisconsin Department of Justice for alleged violations of air management statutes and rules. In June 2014, we settled with the Department of Justice and paid $50,000 in costs and penalties.

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

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

There have been no material changes related to market risk from the disclosures presented in our Annual Report on Form 10-K for the year ended December 31, 2013. For information concerning market risk exposures at Wisconsin Energy Corporation, see Item 7. 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 Part II of our 2013 Annual Report on Form 10-K, as well as Note 6 -- Fair Value Measurements and Note 7 -- Derivative Instruments in the Notes to Consolidated Condensed Financial Statements in this report.

ITEM 4. CONTROLS AND PROCEDURES

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

Internal Control Over Financial Reporting: There has not been any change in our internal control over financial reporting (as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) during the fiscal quarter to which this report relates that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

PART II -- OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

The following should be read in conjunction with Item 3. Legal Proceedings in Part I of our 2013 Annual Report on Form 10-K.

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

ENVIRONMENTAL MATTERS

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

UTILITY RATES AND REGULATORY MATTERS

See Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations -- Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters in Part I of this report for information concerning rate matters in the jurisdictions where Wisconsin Electric and Wisconsin Gas do business.

Form 10-Q

OTHER MATTERS

Litigation Relating to the Acquisition: In June and July 2014, Integrys and its board of directors, along with Wisconsin Energy, were named defendants in six separate purported class action lawsuits filed in Brown County, Wisconsin (three of the cases -- Rubin v. Integrys, et al., Blachor v. Integrys, et al.; and Albera v. Integrys, et al.), Milwaukee County, Wisconsin (Amo v. Integrys, et al.), and Cook County, Illinois (two cases - Taxman v. Integrys, et al. and Curley v. Integrys, et al.). The cases were brought on behalf of proposed classes consisting of shareholders of Integrys. The complaints allege, among other things, that the Integrys board members breached their fiduciary duties by failing to maximize the value to be received by Integrys' shareholders, and that Wisconsin Energy aided and abetted the breaches of fiduciary duty. The complaints seek, among other things, (a) to enjoin defendants from consummating the Acquisition; (b) rescission of the Merger Agreement; and (c) to direct the defendants to exercise their fiduciary duties to obtain the highest value possible for the Integrys shareholders. Wisconsin Energy believes the cases have no merit and intends to defend the actions vigorously.

ITEM 1A. RISK FACTORS

We are subject to a variety of risks, many of which are beyond our control, that may adversely affect our business, financial condition and results of operations. We have identified a number of these risk factors in Item 1A. Risk Factors in our annual Report on Form 10-K for the year ended December 31, 2013, which risk factors are incorporated herein by reference. Other than as set forth below, there have been no material changes to these risk factors. You should carefully consider all of these risk factors, as well as the other information included in this report and other documents filed by us with the SEC from time to time, when making an investment decision.

Risks Related to Our Pending Acquisition of Integrys

We may be unable to satisfy the conditions or obtain the approvals required to complete the Acquisition or such approvals may contain material restrictions or conditions.

Completion of the Acquisition is subject to numerous conditions, including approval of the shareholders of both Wisconsin Energy and Integrys, the approval of various government agencies and the expiration or termination of the waiting period under the HSR Act. We cannot provide assurance that we will obtain all required consents or approvals, or that the regulatory consents or approvals will not impose conditions on the completion, or require changes to the terms, of the Acquisition, including restrictions on the business, operations or financial performance of the combined company. These conditions or changes could also delay or materially and adversely affect the business results and financial condition of the combined company.

The Acquisition may not be completed, which may have an adverse effect on our share price and future business and financial results.

Failure to complete the Acquisition could negatively affect Wisconsin Energy's share price, as well as our future business and financial results. If the Merger Agreement is terminated under specified circumstances set forth in the Merger Agreement, we may be required to pay Integrys a termination fee of $175 million. In addition, we must pay our own costs related to the Acquisition including, among others, legal, accounting, advisory, financing fees, filing and printing costs, whether the Acquisition is completed or not. For these and other reasons, a failure to complete the Acquisition could materially and adversely affect our business, financial results and share price.

While the Acquisition is pending, we are subject to business uncertainties and contractual restrictions that could materially adversely affect our operations and the future of our business.

The Merger Agreement includes restrictions on the conduct of our business prior to the completion of the Acquisition, generally requiring us to conduct our business in the ordinary course and subjecting us to a variety of specified limitations absent Integrys' prior written consent. We may find that these and other contractual arrangements in the Merger Agreement may delay or prevent us from or limit our ability to respond effectively to competitive pressures, industry developments and future business opportunities that may arise during such period, even if our management thinks they may be advisable. The pendency of the Acquisition may also divert management's attention and our resources from ongoing business and operations. If any of these effects were to occur, it could materially and adversely affect our operations and the future of our business, regardless of whether the Acquisition is completed.

If completed, the Acquisition may not achieve its intended results.

We entered into the Merger Agreement with the expectation that the Acquisition would result in various benefits. If the Acquisition is completed, achieving the anticipated benefits will be subject to a number of uncertainties, including whether Wisconsin Energy's and Integrys' businesses can be integrated in an efficient and effective manner. Failure to achieve these anticipated benefits could adversely affect our business, financial results and share price.

Risks Related to Legislation and Regulation

We may face significant costs to comply with the regulation of greenhouse gas emissions.
The regulation of GHG emissions continues to be a top priority for the President's administration. In June 2013, the President issued a presidential memorandum instructing the EPA to, among other things, issue rules pertaining to GHG emissions from both new and existing plants.
In June 2012, the U.S. Court of Appeals for the D.C. Circuit upheld the EPA's authority to regulate GHG emissions. The EPA is pursuing regulation of GHG emissions using its existing authority under the Clean Air Act. In September 2013, the EPA withdrew its 2012 proposed New Source Performance Standards GHG emissions rule, and issued new proposed rules 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.
With respect to existing generating units, the EPA issued a proposed rule on June 18, 2014, and is expected to issue a final rule by June 2015. The proposed rule would require states to submit SIPs as early as June 30, 2016. Single states requesting a one year extension would be required to submit SIPs 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 SIPs by June 30, 2018. We are in the process of reviewing the proposed rule to determine the potential impacts to our operations. We expect that these regulations as currently proposed would impact how we operate our existing facilities, particularly our fossil fueled power plants and biomass facility, and could have a material adverse impact on our operating costs.
Legislation to regulate GHG emissions and establish renewable and efficiency standards has also been considered on the state level. Both Wisconsin and Michigan have adopted renewable portfolio standards and energy optimization (efficiency) targets.
Despite the United States Supreme Court's decision in Connecticut v. American Electric Power Co., where the Court ruled that the plaintiffs in that litigation did not have standing to claim nuisance due to the release of GHG into the atmosphere by the defendants, states and environmental groups have lawsuits pending against electric utilities and others to force reductions in GHG emissions based upon their contribution to the alleged public nuisance of climate change.
There is no guarantee that we will be allowed to fully recover costs incurred to comply with legislation, regulation or orders requiring a reduction in GHG emissions or that cost recovery will not be delayed or otherwise conditioned. Any legislation or regulation that may ultimately be adopted, either at the federal or state level, designed to reduce GHG emissions could have a material adverse impact on our electric generation and natural gas distribution operations. Such regulation could make some of our electric generating units uneconomic to maintain or operate, and could adversely affect our future results of operations, cash flows and possibly financial condition if such costs are not recovered through regulated rates.

A decrease in the return on equity earned by participants in MISO could have a negative impact on our results of operations.

On June 19, 2014, FERC issued an order revising its methodology for determining the base return on equity for jurisdictional electric utilities, including transmission owners. FERC expects its new methodology will narrow the "zone" of reasonable returns on equity. FERC also indicated that it will continue its policy that an electric utility's total return on equity is limited to the zone of reasonableness. FERC has set five complaints challenging electric utilities base return on equity for hearing and settlement procedures, and indicated that it expects the participants in these proceedings to use its new methodology. In addition, there are several other complaints that have not yet been scheduled for hearing by FERC, one of which is a complaint against MISO and the transmission owners participating in MISO. There is a risk that FERC would reduce the allowed return on equity ATC receives as a transmission owning member of MISO, which ultimately could reduce our earnings with respect to our investment in ATC.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

The following table sets forth information regarding the purchases of our equity securities made by or on behalf of us or any affiliated purchaser (as defined in Exchange Act Rule 10b-18) during the three months ended June 30, 2014:

ISSUER PURCHASES OF EQUITY SECURITIES

2014	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (a)	Maximum Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (Millions of Dollars)	
April 1 - April 30	—	$—	—	$281.4	
May 1 - May 31	—	$—	—	$281.4	
June 1 - June 30	—	$—	—	$—	(a)
Total	—	$—	—		

(a) On December 5, 2013, Wisconsin Energy's Board of Directors authorized a share repurchase program for up to $300 million of our common stock effective January 1, 2014, through December 31, 2017. In connection with the Acquisition, the Board of Directors terminated this share repurchase program effective June 22, 2014.

Form 10-Q

ITEM 6. EXHIBITS

Exhibit No.	
2	Plan of Acquisition, Reorganization, Arrangement, Liquidation or Succession
2.1	Agreement and Plan of Merger, dated as of June 22, 2014, by and between Wisconsin Energy and Integrys. (Exhibit 2.1 to Wisconsin Energy's 06/22/2014 Form 8-K.)
4	Instruments Defining the Rights of Security Holders
4.1	Securities Resolution No. 14 of Wisconsin Electric, dated as of May 12, 2014, under the Indenture for Debt Securities, dated as of December 1, 1995, between Wisconsin Electric and U.S. Bank National Association (as successor to Firstar Trust Company), as Trustee. (Exhibit 4.1 to Wisconsin Electric's 05/15/2014 Form 8-K.)
31	Rule 13a-14(a) / 15d-14(a) Certifications
31.1	Certification Pursuant to Rule 13a-14(a) or 15d-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification Pursuant to Rule 13a-14(a) or 15d-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32	Section 1350 Certifications
32.1	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101	Interactive Data File

Form 10-Q

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

	WISCONSIN ENERGY CORPORATION (Registrant)
Date: August 1, 2014	/s/STEPHEN P. DICKSON Stephen P. Dickson, Vice President and Controller, Principal Accounting Officer and duly authorized officer