WISCONSIN ENERGY CORP
Form 10-Q
July 30, 2010

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, 2010**

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, 2010):

Common Stock, $.01 Par Value,	116,897,894 shares outstanding.

WISCONSIN ENERGY CORPORATION

FORM 10-Q REPORT FOR THE QUARTER ENDED JUNE 30, 2010

TABLE OF CONTENTS

Item		Page
	Introduction	7
	Part I -- Financial Information	
1.	Financial Statements	
	Consolidated Condensed Income Statements	8
	Consolidated Condensed Balance Sheets	9
	Consolidated Condensed Statements of Cash Flows	10
	Notes to Consolidated Condensed Financial Statements	11
2.	Management's Discussion and Analysis of	

	Financial Condition and Results of Operations	24
3.	Quantitative and Qualitative Disclosures About Market Risk	38
4.	Controls and Procedures	38

Part II -- Other Information

1.	Legal Proceedings	38
1A.	Risk Factors	39
2.	Unregistered Sales of Equity Securities and Use of Proceeds	39
6.	Exhibits	40
	Signatures	41

DEFINITION OF ABBREVIATIONS AND INDUSTRY TERMS

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

Wisconsin Energy Subsidiaries and Affiliates

Primary Subsidiaries

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
PWGS	Port Washington Generating Station
PWGS 1	Port Washington Generating Station Unit 1
PWGS 2	Port Washington Generating Station Unit 2

Other Subsidiaries and Affiliates

ERGSS	Elm Road Generating Station Supercritical, LLC

Federal and State Regulatory Agencies

DOE	United States Department of Energy
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
MPSC	Michigan Public Service Commission
PSCW	Public Service Commission of Wisconsin
SEC	Securities and Exchange Commission

Environmental Terms

CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
NO_x	Nitrogen Oxide
$PM_{2.5}$	Fine Particulate Matter
SO_2	Sulfur Dioxide

Other Terms and Abbreviations

AQCS	Air Quality Control Sytem
ARRs	Auction Revenue Rights
Bechtel	Bechtel Power Corporation
Compensation Committee	Compensation Committee of the Board of Directors
CPCN	Certificate of Public Convenience and Necessity
Edison Sault	Edison Sault Electric Company
ERISA	Employee Retirement Income Security Act of 1974
Fitch	Fitch Ratings
FTRs	Financial Transmission Rights
Junior Notes	Wisconsin Energy's 2007 Series A Junior Subordinated Notes due 2067 issued in May 2007
LMP	Locational Marginal Price
MISO	Midwest Independent Transmission System Operator, Inc.
Moody's	Moody's Investor Service
OTC	Over-the-Counter
Plan	The Wisconsin Energy Corporation Retirement Account Plan
Point Beach	Point Beach Nuclear Power Plant
PSEG	Public Service Enterprise Group
PTF	Power the Future
S&P	Standard & Poor's Ratings Services

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:

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

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. These statements are based upon management's current expectations and are subject to risks and uncertainties that could cause our actual results to differ materially from those contemplated in the statements. Readers are cautioned not to place undue reliance on these forward-looking statements. Forward-looking statements include, among other things, statements concerning management's expectations and projections regarding earnings, completion of construction projects, regulatory matters, fuel costs, sources of electric energy supply, coal and gas deliveries, remediation costs, environmental and other capital expenditures, liquidity and capital resources and other matters. In some cases, forward-looking statements may be identified by reference to a future period or periods or by the use of forward-looking terminology such as "anticipates," "believes," "estimates," "expects," "forecasts," "guidance," "intends," "may," "objectives," "plans," "possible," "potential," "projects," "should" or similar terms or variations of these terms.

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

of operations and financial condition include, among others, the following:

- Factors affecting utility operations such as unusual weather conditions; catastrophic weather-related or terrorism-related damage; availability of electric generating facilities; unscheduled generation outages, or unplanned maintenance or repairs; unanticipated events causing scheduled generation outages to last longer than expected; unanticipated changes in fossil fuel, purchased power, coal supply, gas supply or water supply costs or availability due to higher demand, shortages, transportation problems or other developments; nonperformance by electric energy or natural gas suppliers under existing power purchase or gas supply contracts; environmental incidents; electric transmission or gas pipeline system constraints; unanticipated organizational structure or key personnel changes; collective bargaining agreements with union employees or work stoppages; or inflation rates.

- Factors affecting the economic climate in our service territories such as customer growth; customer business conditions, including demand for their products and services; and changes in market demand and demographic patterns.

- Timing, resolution and impact of pending and future rate cases and negotiations, including recovery for new investments as part of our *Power the Future (*PTF) strategy, environmental compliance, transmission service, fuel costs and costs associated with the Midwest Independent Transmission System Operator, Inc. (MISO) Energy and Operating Reserve Markets.

- Regulatory factors such as changes in rate-setting policies or procedures; changes in regulatory accounting policies and practices; industry restructuring initiatives; transmission or distribution system operation and/or administration initiatives; required changes in facilities or operations to reduce the risks or impacts of potential terrorist activities; required approvals for new construction; and the siting approval process for new generation and transmission facilities and new pipeline construction.

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

- Factors which impede or delay execution of our PTF strategy, including the adverse interpretation or enforcement of permit conditions by the permitting agencies; construction delays; and obtaining the investment capital from outside sources necessary to implement the strategy.

- The impact of recent and future federal, state and local legislative and regulatory changes, including electric and gas industry restructuring initiatives; changes to the Federal Power Act and related regulations under the Energy Policy Act of 2005 and enforcement thereof by the Federal Energy Regulatory Commission (FERC) and other regulatory agencies; changes in allocation of energy assistance, including state public benefits funds; changes in environmental, tax and other laws and regulations to which we are subject; changes in the application of existing laws and regulations; and changes in the interpretation or enforcement of permit conditions by the permitting agencies.

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

- The cost and other effects of legal and administrative proceedings, settlements, investigations, claims and changes in those matters.

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

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

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

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

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

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

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

- The 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.

- 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, 2009.

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 is a diversified holding company which conducts its operations primarily in two operating segments: a utility energy segment and a non-utility energy segment. Unless qualified by their context when used in this document, the terms Wisconsin Energy, the Company, our, us or we refer to the holding company and all of its subsidiaries. Our 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".

In April 2010, Wisconsin Electric and Wisconsin Gas filed a joint application with the Public Service Commission of Wisconsin (PSCW) to merge Wisconsin Gas into Wisconsin Electric.

Non-Utility Energy Segment:

Our non-utility energy segment consists primarily of We Power. We Power was formed in 2001 to design, construct, own and lease to Wisconsin Electric the new generating capacity included in our PTF strategy. See Item 7 - Management's Discussion and Analysis of Financial Condition and Results of Operations in our 2009 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 GAAP pursuant to these rules and regulations. This Form 10-Q, including the financial statements contained herein, should be read in conjunction with our 2009 Annual Report on Form 10-K, including the financial statements and notes therein.

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	
	2010	2009	2010	2009
	(Millions of Dollars, Except Per Share Amounts)			
Operating Revenues	$890.9	$835.7	$2,139.5	$2,224.1
Operating Expenses				
Fuel and purchased power	258.4	252.5	535.8	517.4
Cost of gas sold	95.8	102.0	451.6	604.7

Other operation and maintenance	317.5	304.6	652.9	635.4
Depreciation and amortization	76.8	85.6	151.2	170.6
Property and revenue taxes	26.3	27.7	52.9	55.4
Total Operating Expenses	774.8	772.4	1,844.4	1,983.5
Amortization of Gain	47.2	55.1	96.6	119.3
Operating Income	163.3	118.4	391.7	359.9
Equity in Earnings of Transmission Affiliate	15.1	14.4	30.3	28.7
Other Income, net	9.7	7.4	15.9	13.8
Interest Expense, net	53.0	39.8	102.4	80.6
Income from Continuing Operations Before Income Taxes	135.1	100.4	335.5	321.8
Income Taxes	47.6	37.4	119.0	117.4
Income from Continuing Operations	87.5	63.0	216.5	204.4
Income from Discontinued Operations, Net of Tax	1.2	0.7	1.9	0.8
Net Income	$88.7	$63.7	$218.4	$205.2
Earnings Per Share (Basic)				
Continuing operations	$0.75	$0.54	$1.85	$1.75
Discontinued operations	0.01	-	0.02	-
Total Earnings Per Share (Basic)	$0.76	$0.54	$1.87	$1.75
Earnings Per Share (Diluted)				
Continuing operations	$0.74	$0.53	$1.83	$1.73
Discontinued operations	0.01	0.01	0.02	0.01
Total Earnings Per Share (Diluted)	$0.75	$0.54	$1.85	$1.74
Weighted Average Common Shares Outstanding (Millions)				
Basic	116.9	116.9	116.9	116.9
Diluted	118.3	117.8	118.3	117.9
Dividends Per Share of Common Stock	$0.40	$0.3375	$0.80	$0.6750

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

WISCONSIN ENERGY CORPORATION
CONSOLIDATED CONDENSED BALANCE SHEETS

	(Unaudited) June 30, 2010	December 31, 2009
	(Millions of Dollars)	
Assets		
Property, Plant and Equipment		
In service	$ 11,444.7	$ 10,192.1
Accumulated depreciation	(3,538.9)	(3,431.9)
	7,905.8	6,760.2
Construction work in progress	1,316.5	2,185.1
Leased facilities, net	67.7	70.5
Net Property, Plant and Equipment	9,290.0	9,015.8
Investments		
Equity investment in transmission affiliate	323.9	314.6
Other	38.9	44.1
Total Investments	362.8	358.7
Current Assets		
Cash and cash equivalents	10.5	20.2
Restricted cash	112.7	194.5
Accounts receivable	317.3	298.7
Accrued revenues	177.2	288.7
Materials, supplies and inventories	390.2	378.1
Regulatory assets	54.4	58.9
Prepayments and other	210.7	290.2
Total Current Assets	1,273.0	1,529.3
Deferred Charges and Other Assets		
Regulatory assets	1,143.2	1,180.5
Goodwill	441.9	441.9
Other	182.6	171.7
Total Deferred Charges and Other Assets	1,767.7	1,794.1

Total Assets	$ 12,693.5	$ 12,697.9
Capitalization and Liabilities		
Capitalization		
Common equity	$ 3,677.1	$ 3,566.9
Preferred stock of subsidiary	30.4	30.4
Long-term debt	3,942.6	3,875.8
Total Capitalization	7,650.1	7,473.1
Current Liabilities		
Long-term debt due currently	493.3	295.7
Short-term debt	520.4	825.1
Accounts payable	270.5	290.6
Regulatory liabilities	121.3	222.8
Other	247.2	259.9
Total Current Liabilities	1,652.7	1,894.1
Deferred Credits and Other Liabilities		
Regulatory liabilities	890.7	876.0
Deferred income taxes - long-term	1,039.6	1,017.9
Deferred revenue, net	778.1	739.1
Pension and other benefit obligations	329.4	318.7
Other	352.9	379.0
Total Deferred Credits and Other Liabilities	3,390.7	3,330.7
Total Capitalization and Liabilities	$ 12,693.5	$ 12,697.9

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

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

		Six Months Ended June 30	
		2010	2009
		(Millions of Dollars)	
Operating Activities			
Net income		$ 218.4	$ 205.2
Reconciliation to cash			
Depreciation and amortization		157.4	177.8
Amortization of gain		(96.6)	(119.3)
Equity in earnings of transmission affiliate		(30.3)	(28.7)
Distributions from transmission affiliate		24.8	22.8
Deferred income taxes and investment tax credits, net		7.3	14.6
Deferred revenue		55.0	97.5
Contributions to benefit plans		-	(289.3)
Change in -	Accounts receivable and accrued revenues	72.5	168.2
	Inventories	(12.1)	30.2
	Other current assets	20.4	18.0
	Accounts payable	(29.8)	(156.7)
	Accrued income taxes, net	(13.3)	99.5
	Deferred costs, net	13.0	23.1
	Other current liabilities	14.7	(11.9)
Other, net		22.3	(20.0)
Cash Provided by Operating Activities		423.7	231.0
Investing Activities			
Capital expenditures		(379.1)	(363.4)
Investment in transmission affiliate		(3.9)	(11.5)
Proceeds from asset sales, net		63.5	14.8
Change in restricted cash		81.8	103.1
Other, net		(37.6)	(47.8)
Cash Used in Investing Activities		(275.3)	(304.8)
Financing Activities			
Exercise of stock options		43.2	6.3
Purchase of common stock		(68.9)	(10.5)
Dividends paid on common stock		(93.5)	(78.9)
Issuance of long-term debt		530.0	11.5
Retirement and repurchase of long-term debt		(263.5)	(53.3)
Change in short-term debt		(304.7)	177.9
Other, net		(0.7)	0.9
Cash (Used in) Provided by Financing Activities		(158.1)	53.9

Change in Cash and Cash Equivalents	(9.7)	(19.9)
Cash and Cash Equivalents at Beginning of Period	20.2	31.7
Cash and Cash Equivalents at End of Period	$ 10.5	$ 11.8

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

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 2009 Annual Report on Form 10-K. In the opinion of management, we have included all adjustments, normal and recurring in nature, necessary to 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, 2010 are not necessarily indicative of the results which may be expected for the entire fiscal year 2010 because of seasonal and other factors.

Reclassifications:

We have reclassified certain prior year financial statement amounts to conform to their current year presentation. These reclassifications had no effect on total assets, net income or earnings per share.

The reclassifications relate to the reporting of discontinued operations reflecting the sale of Edison Sault. The footnotes contained herein reflect continuing operations for all periods presented. For further information, see Note 5 -- Discontinued Operations and Divestitures.

2 -- NEW ACCOUNTING PRONOUNCEMENTS

Amendments to Variable Interest Entity Consolidation Guidance:

In June 2009, the Financial Accounting Standards Board issued new accounting guidance related to variable interest entity consolidation. The purpose of this guidance is to improve financial reporting by enterprises with variable interest entities. The new guidance is effective for all new and existing variable interest entities for fiscal years beginning after November 15, 2009. We adopted these provisions on January 1, 2010. This adoption did not have any impact on our financial condition, results of operations or cash flows. See Note 12 -- Variable Interest Entities for required disclosures.

3 -- Accounting and Reporting for Power the Future Generating Units

Background:

As part of our PTF strategy, our non-utility subsidiary, We Power, has built three new generating units, Port Washington Generating Station Unit 1 (PWGS 1), Port Washington Generating Station Unit 2 (PWGS 2) and Oak Creek expansion Unit 1 (OC 1)) and is in the process of building another new generating unit, Oak Creek expansion Unit 2 (OC 2), which are, and will be, leased to our utility subsidiary, Wisconsin Electric, under long-term leases that have been approved by the Public Service Commission of Wisconsin (PSCW). The leases are designed to recover the capital costs of the plant, including a return. PWGS 1, PWGS 2 and OC 1 were placed in service in July 2005, May 2008 and February 2010, respectively. The accompanying consolidated financial statements eliminate all intercompany transactions between We Power and Wisconsin Electric and reflect the cash inflows from Wisconsin Electric customers and the cash outflows to our vendors and suppliers.

The Oak Creek expansion includes common projects that will benefit the existing units at this site as well as the new units. These projects include a coal handling facility and a water intake system, which were placed into service in November 2007 and January 2009, respectively.

During Construction:

Under the terms of each lease, we collect in current rates amounts representing our pre-tax cost of capital (debt and equity) associated with capital expenditures for our PTF units. Our pre-tax cost of capital is approximately 14%. The carrying costs that we collect in rates are recorded as deferred revenue and will be amortized to revenue over the term of each lease once the respective unit is placed into service. During the construction of our PTF units, we capitalize interest costs at an overall weighted-average pre-tax cost of interest which was approximately 5% for the six months ended June 30, 2010 and for the twelve months ended December 31, 2009. Capitalized interest is included in the total cost of the PTF units.

Plant in Service:

Once the PTF units are placed in service, we expect to recover in rates the lease costs which reflect the authorized cash construction costs of the units plus a return on the investment. The authorized cash costs are established by the PSCW. The authorized cash costs exclude capitalized interest since carrying costs are recovered during the construction of the units. The lease payments are expected to be levelized, except that OC 1 and OC 2 will be recovered on a levelized basis that has a one time 10.6% escalation after the first five years of the leases. The leases established a set return on equity component of 12.7% after tax. The interest component of the return is determined up to 180 days prior to the date that the units are placed in service.

We recognize revenues (consisting of the lease payments included in rates and the amortization of the deferred revenue) on a levelized basis over the term of the lease. We depreciate the units on a straight-line basis over their expected service life.

4 -- COMMON EQUITY

Share-Based Compensation Expense:

For a description of share-based compensation, including stock options, restricted stock and performance units, see Note J -- Common Equity in our 2009 Annual Report on Form 10-K. We utilize the straight-line attribution method for recognizing share-based compensation expense. Accordingly, for employee awards, equity classified share-based compensation cost is measured at the grant date based on the fair value of the award, and is recognized as expense over the requisite service period. There were no modifications to outstanding stock options during the period. Shares purchased on the open market by our independent agents are currently used to satisfy share-based awards.

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

	Three Months Ended June 30		Six Months Ended June 30	
	2010	2009	2010	2009
	(Millions of Dollars)			
Stock options	$1.9	$2.8	$3.8	$5.3
Performance units	7.9	0.1	10.6	3.9
Restricted stock	0.5	0.3	0.8	0.5
Share-based compensation expense	$10.3	$3.2	$15.2	$9.7
Related Tax Benefit	$4.1	$1.3	$6.1	$3.9

Stock Option Activity:

During the first six months of 2010, the Compensation Committee granted 274,750 stock options that had an estimated fair value of $6.72 per share. During the first six months of 2009, the Compensation Committee granted 1,216,625 stock options that had an estimated fair value of $8.01 per share. The following assumptions were used to value the options using a binomial option pricing model:

	2010	2009
Risk free interest rate	0.2% - 3.9%	0.3% - 2.5%
Dividend yield	3.7%	3.0%
Expected volatility	20.3%	25.9%
Expected forfeiture rate	2.0%	2.0%

Expected life (years)	5.9	6.2

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, 2010:

Stock Options	Number of Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (Millions)
Outstanding as of April 1, 2010	8,726,986	$39.34		
Granted	-	$ -		
Exercised	(711,921)	$32.74		
Forfeited	-	$ -		
Outstanding as of June 30, 2010	8,015,065	$39.93		
Outstanding as of January 1, 2010	9,087,315	$38.49		
Granted	274,750	$49.84		
Exercised	(1,342,000)	$32.22		
Forfeited	(5,000)	$45.70		
Outstanding as of June 30, 2010	8,015,065	$39.93	5.8	$86.7
Exercisable as of June 30, 2010	5,277,575	$36.93	4.6	$72.9

The intrinsic value of options exercised was $13.6 million and $25.1 million for the three and six months ended June 30, 2010, and $1.4 million and $3.9 million for the same periods in 2009, respectively. Cash received from options exercised was $43.2 million and $6.3 million for the six months ended June 30, 2010 and 2009, respectively. The actual tax benefit realized for the tax deductions from option exercises for the same periods was approximately $9.7 million and $1.6 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 2010.

The following table summarizes information about stock options outstanding as of June 30, 2010:

	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)
$20.39 to $29.13	987,580	$24.83	2.2	987,580	$24.83	2.2
$33.44 to $39.48	2,827,277	$35.64	4.5	2,827,277	$35.64	4.5
$42.22 to $49.84	4,200,208	$46.37	7.6	1,462,718	$47.60	6.6
	8,015,065	$39.93	5.8	5,277,575	$36.93	4.6

The following table summarizes information about our non-vested options during the three and six months ended June 30, 2010:

Non-Vested Stock Options	Number of Options	Weighted-Average Fair Value
Non-vested as of April 1, 2010	2,779,545	$ 8.53
Granted	-	$ -
Vested	(42,055)	$ 8.62
Forfeited	-	$ -
Non-vested as of June 30, 2010	2,737,490	$ 8.53
Non-vested as of January 1, 2010	3,665,100	$ 8.73
Granted	274,750	$ 6.72
Vested	(1,197,360)	$ 8.72
Forfeited	(5,000)	$ 8.53
Non-vested as of June 30, 2010	2,737,490	$ 8.53

As of June 30, 2010, total compensation costs related to non-vested stock options not yet recognized was approximately $5.4 million, which is expected to be recognized over the next 13 months on a weighted-average basis.

Restricted Shares:

During the first six months of 2010, the Compensation Committee granted 46,740 restricted shares to certain key employees and directors. These awards have a three-year vesting period, with, typically, one-third of the award vesting on each anniversary of the grant date. During the vesting period, restricted share recipients have voting rights and are entitled to dividends in the same manner as other shareholders.

The following restricted stock activity occurred during the three and six months ended June 30, 2010:

Restricted Shares	Number of Shares	Weighted-Average Grant Date Fair Value
Outstanding as of April 1, 2010	133,261	
Granted	-	
Released	(6,181)	$24.08
Forfeited	(215)	$49.55
Outstanding as of June 30, 2010	126,865	
Outstanding as of January 1, 2010	99,649	
Granted	46,740	$49.55
Released	(19,249)	$39.59
Forfeited	(275)	$49.55
Outstanding as of June 30, 2010	126,865	

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 $0.3 million and $1.0 million for the three and six months ended June 30, 2010, and $0.1 million and $0.7 million for the same periods in 2009. The actual tax benefits realized for the tax deductions from released restricted shares was $0.1 million and $0.2 million for the three and six months ended June 30, 2010, and $0.1 million and $0.3 million for the same periods in 2009, respectively.

As of June 30, 2010, total compensation cost related to restricted stock not yet recognized was approximately $2.9 million, which is expected to be recognized over the next 28 months on a weighted-average basis.

Performance Units:

In January 2010 and 2009, the Compensation Committee granted 277,915 and 333,220 performance units, respectively, to officers and other key employees under the Wisconsin Energy Performance Unit Plan. Under the grants, the ultimate number of units that will be awarded is dependent upon the achievement of certain financial performance of our stock over a three-year period. Under the terms of the award, participants may earn between 0% and 175% of the base performance unit award. All grants are settled in cash. We are accruing compensation costs over the three-year period based on our estimate of the final expected value of the awards. Performance units earned as of December 31, 2009 and 2008 vested and were settled during the first quarter of 2010 and 2009, and had a total intrinsic value of $9.8 million and $8.4 million, respectively. The actual tax benefit realized for the tax deductions from the settlement of performance units was approximately $3.4 million and $3.1 million, respectively. As of June 30, 2010, total compensation costs related to performance units not yet recognized was approximately $24.1 million, which is expected to be recognized over the next 23 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 principal utility 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 J --Common Equity in our 2009 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.

Comprehensive Income:

Comprehensive income includes all changes in equity during a period except those resulting from investments by and distributions to owners.

Our total comprehensive income for the six months ended June 30, 2010 and 2009 was $218.6 million and $205.4 million, respectively, which approximates net income for each of those periods.

5 -- DISCONTINUED OPERATIONS and Divestitures

Edison Sault Electric Company (Edison Sault):

Effective May 4, 2010, we sold Edison Sault to Cloverland Electric Cooperative for approximately $63.0 million.

The assets and liabilities ($77.0 million and $15.1 million, respectively) associated with Edison Sault were reclassified as held for sale within other current assets and liabilities on our Consolidated Condensed Balance Sheet as of December 31, 2009. We also reclassified the income related to Edison Sault as discontinued operations in the accompanying Consolidated Condensed Income Statements. Discontinued Edison Sault operations had no significant impact on our Consolidated Condensed Statements of Cash Flows for the six months ended June 30, 2010 and 2009, respectively.

A summary of the components of Income from Discontinued Operations, Net of Tax in our Consolidated Condensed Income Statements follows:

	Three Months Ended June 30		Six Months Ended June 30	
	2010 (a)	2009	2010 (a)	2009
	(Millions of Dollars)			

Operating revenues (b)	$1.9	$6.8	$9.3	$14.6
Operating expenses (b)	1.8	6.0	7.9	12.3
Income before income taxes	0.1	0.8	1.4	2.3
Income tax expense	0.1	0.4	0.7	1.8
Income (Loss) from discontinued Edison Sault operations, net of tax	-	0.4	0.7	0.5
Gain on Sale of Edison Sault, net of tax	1.1	-	1.1	-
Income from discontinued other operations, net of tax	0.1	0.3	0.1	0.3
Total Income from Discontinued Operations, Net of Tax	$1.2	$0.7	$1.9	$0.8

(a) As a result of its sale effective May 4, 2010, we owned Edison Sault for approximately one of the three months ended June 30, 2010 and for approximately four of the six months ended June 30, 2010.

(b) Amounts are net of intercompany activity.

Edgewater Generating Unit 5:

During the fourth quarter of 2009, we reached a contingent agreement to sell our 25% interest in Edgewater Generating Unit 5 to Wisconsin Power and Light Company, a subsidiary of Alliant Energy Corp., for our net book value, including working capital. In March 2010, the agreement became effective and we are in the process of receiving regulatory approvals. The completion of the sale is subject to approval by applicable regulatory bodies, including the PSCW and Michigan Public Service Commission (MPSC). In June 2010, we received approval for the sale from FERC. If approved by the remaining regulatory bodies, we expect the sale to close by the end of 2010 and to realize proceeds of between $40 million and $45 million depending on the working capital balances and our level of capital investment in the unit prior to the sale.

6 -- LONG-TERM DEBT

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

7 -- 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 -- Quoted prices are 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, 2010			
	Level 1	Level 2	Level 3	Total
		(Millions of Dollars)		
Assets:				
Restricted Cash	$112.7	$ -	$ -	$112.7
Derivatives	0.3	7.6	15.9	23.8
Total	$113.0	$7.6	$15.9	$136.5
Liabilities:				
Derivatives	$8.3	$5.4	$ -	$13.7
Total	$8.3	$5.4	$ -	$13.7

Recurring Fair Value Measures	As of December 31, 2009			
	Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Assets:				
Restricted Cash	$194.5	$ -	$ -	$194.5
Derivatives	0.7	4.2	5.8	10.7
Total	$195.2	$4.2	$5.8	$205.2
Liabilities:				
Derivatives	$4.5	$4.8	$ -	$9.3
Total	$4.5	$4.8	$ -	$9.3

Restricted cash consists of certificates of deposit and government backed interest bearing securities and represents the remaining funds to be distributed to customers resulting from the net proceeds received from the sale of Point Beach Nuclear Power Plant (Point Beach). 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 tables summarize the fair value of derivatives classified as Level 3 in the fair value hierarchy:

Quarter to Date	2010	2009
	(Millions of Dollars)	
Balance as of April 1	$1.9	$2.9
Realized and unrealized gains (losses)	-	-
Purchases, issuances and settlements	14.0	12.5
Transfers in and/or out of Level 3	-	-
Balance as of June 30	$15.9	$15.4
Change in unrealized gains (losses) relating to instruments still held as of June 30	$ -	$ -

Year to Date	2010	2009

	(Millions of Dollars)	
Balance as of January 1	$5.8	$8.8
Realized and unrealized gains (losses)	-	-
Purchases, issuances and settlements	10.1	6.6
Transfers in and/or out of Level 3	-	
Balance as of June 30	$15.9	$15.4
Change in unrealized gains (losses) relating to instruments still held as of June 30	$ -	$ -

Derivative instruments reflected in Level 3 of the hierarchy include 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 8 -- Derivative Instruments, for further information on the offset to regulatory assets and liabilities.

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

	June 30, 2010		December 31, 2009	
Financial Instruments	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(Millions of Dollars)			
Preferred stock, no redemption required	$30.4	$21.7	$30.4	$20.2
Long-term debt including current portion	$4,316.3	$4,645.0	$4,049.8	$4,162.5

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.

8 -- DERIVATIVE INSTRUMENTS

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

We record derivative instruments on the balance sheet as an asset or liability measured at its fair value, and changes in the derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are met or we receive regulatory treatment for the derivative. For most energy related physical and financial contracts in our regulated operations that qualify as derivatives, the PSCW allows the effects of the fair market value accounting to be offset to regulatory assets and liabilities. We do not offset fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral against fair value amounts recognized for derivatives executed with the same counterparty under the same master netting arrangement. As of June 30, 2010, we recognized $22.5 million in regulatory assets and $23.6 million in regulatory liabilities related to derivatives in comparison to $19.1 million in regulatory assets and $10.3 million in regulatory liabilities as of December 31, 2009.

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. The long-term portion of our derivative assets of $0.9 million is recorded in Other deferred charges and other assets and the long-term portion of our derivative liabilities of $0.9 million is recorded in Other deferred credits and other liabilities. Our Consolidated Condensed Balance Sheet as of June 30, 2010 and December 31, 2009 includes:

	June 30, 2010		December 31, 2009	
	Derivative Asset	Derivative Liability	Derivative Asset	Derivative Liability
	(Millions of Dollars)			
Natural Gas	$4.8	$13.3	$2.2	$9.3
Energy	-	0.4	-	-
Fuel Oil	0.2	-	0.6	-
FTRs	15.9	-	5.8	-
Coal	2.9	-	2.1	-
Total	$23.8	$13.7	$10.7	$9.3

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 gain (losses) for the three and six months ended June 30, 2010 and 2009 follow:

	Three Months Ended June 30, 2010		Three Months Ended June 30, 2009	
	Volume	Gains (Losses)	Volume	Gains (Losses)
		(Millions of Dollars)		(Millions of Dollars)
Natural Gas	19.3 million Dth	($9.1)	23.3 million Dth	($28.7)
Energy	102,400 MWh	(0.2)	3,200 MWh	(0.1)
Fuel Oil	2.0 million gallons	-	1.3 million gallons	(1.0)
FTRs	6,657 MW	3.2	5,605 MW	3.7
Total		($6.1)		($26.1)

	Six Months Ended June 30, 2010		Six Months Ended June 30, 2009	
	Volume	Gains (Losses)	Volume	Gains (Losses)
		(Millions of Dollars)		(Millions of Dollars)
Natural Gas	47.6 million Dth	($20.7)	45.7 million Dth	($54.0)
Energy	159,600 MWh	-	15,120 MWh	(0.6)
Fuel Oil	3.8 million gallons	-	2.2 million gallons	(1.3)
FTRs	12,088.4 MW	12.2	11,785 MW	4.2
Total		($8.5)		($51.7)

As of June 30, 2010 and December 31, 2009, we have posted collateral of $16.2 million and $9.3 million, respectively, in our margin accounts. These amounts are recorded on the balance sheet in Prepayments and other current assets.

9 -- 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, 2010 and 2009 were as follows:

	Pension Costs			
	Three Months Ended June 30		Six Months Ended June 30	
Benefit Plan Cost Components	2010	2009	2010	2009
	(Millions of Dollars)			
Net Periodic Benefit Cost				
Service cost	$4.9	$6.4	$11.8	$11.7
Interest cost	16.4	17.9	33.8	36.1
Expected return on plan assets	(19.0)	(24.0)	(38.7)	(47.7)
Amortization of:				
Transition obligation	-	-	-	-
Prior service cost	0.5	0.5	1.1	1.1
Actuarial loss	6.7	4.2	13.3	9.4
Net Periodic Benefit Cost	$9.5	$5.0	$21.3	$10.6

	OPEB Costs	
	Three Months Ended June 30	Six Months Ended June 30

Benefit Plan Cost Components	2010	2009	2010	2009
			(Millions of Dollars)	
Net Periodic Benefit Cost				
Service cost	$2.8	$2.0	$5.6	$4.3
Interest cost	5.1	5.0	10.5	10.3
Expected return on plan assets	(3.6)	(3.3)	(7.2)	(6.8)
Amortization of:				
Transition obligation	0.1	-	0.2	0.1
Prior service (credit)	(2.9)	(3.1)	(5.9)	(6.3)
Actuarial loss	2.7	2.2	5.4	4.5
Net Periodic Benefit Cost	$4.2	$2.8	$8.6	$6.1

10 -- GUARANTEES

We enter into various guarantees to provide financial and performance assurance to third parties on behalf of our affiliates. As of June 30, 2010, we had the following guarantees:

Maximum Potential Future Payments	Outstanding	Liability Recorded
	(Millions of Dollars)	
$3.0	$0.2	$ -

A non-utility energy segment guarantee in support of Wisvest-Connecticut, which we sold in December 2002 to Public Service Enterprise Group (PSEG), provides financial assurance for potential obligations relating to environmental remediation under the original purchase agreement for Wisvest-Connecticut with The United Illuminating Company. The potential obligations for environmental remediation, which are unlimited, are reimbursable by PSEG under the terms of the sale agreement in the event that we are required to perform under the guarantee.

We also provide guarantees to support obligations of our affiliates to third parties under loan agreements and surety bonds. In the event our affiliates fail to perform, we would be responsible for the obligations.

Wisconsin Electric is subject to the potential retrospective premiums that could be assessed under its insurance program.

Postemployment Benefits:

Postemployment benefits provided to former or inactive employees are recognized when an event occurs. The estimated liability for such benefits was $16.0 million as of June 30, 2010 and $15.8 million as of December 31, 2009.

11 -- SEGMENT INFORMATION

Summarized financial information concerning our operating segments for the three and six months ended June 30, 2010 and 2009 is shown in the following table:

	Operating Segments Energy		Corporate & Other (a) & Reconciling	Total
Wisconsin Energy Corporation	Utility	Non-Utility	Items	Consolidated
	(Millions of Dollars)			
Three Months Ended				
June 30, 2010				
Operating Revenues (b)	$880.5	$86.6	($76.2)	$890.9
Depreciation and Amortization	$62.7	$13.9	$0.2	$76.8
Operating Income (Loss)	$97.8	$66.9	($1.4)	$163.3
Equity in Earnings of Unconsolidated Affiliates	$15.1	$ -	$ -	$15.1
Interest Expense, Net	$29.5	$10.5	$13.0	$53.0
Income Tax Expense (Benefit)	$32.0	$22.1	($6.5)	$47.6
Income (Loss) from Discontinued Operations, Net of Tax	($0.1)	$ -	$1.3	$1.2
Net Income (Loss)	$60.8	$34.2	($6.3)	$88.7
Capital Expenditures	$164.7	$19.8	$0.4	$184.9

	Operating Segments Energy		Corporate & Other (a) & Reconciling	Total
Wisconsin Energy Corporation	Utility	Non-Utility	Items	Consolidated
	(Millions of Dollars)			

	Three Months Ended			
June 30, 2009				
Operating Revenues (b)	$833.0	$44.1	($41.5)	$835.7
Depreciation and Amortization	$78.1	$7.3	$0.2	$85.6
Operating Income (Loss)	$89.4	$30.8	($1.8)	$118.4
Equity in Earnings of Unconsolidated Affiliates	$14.4	$ -	$ -	$14.4
Interest Expense, Net	$29.5	$4.1	$6.2	$39.8
Income Tax Expense (Benefit)	$31.1	$11.1	($4.8)	$37.4
Income from Discontinued Operations, Net of Tax	$0.6	$ -	$0.1	$0.7
Net Income (Loss)	$50.4	$16.6	($3.3)	$63.7
Capital Expenditures	$143.0	$43.5	$5.5	$192.0

	Six Months Ended			
June 30, 2010				
Operating Revenues (b)	$2,123.4	$152.1	($135.8)	$2,139.5
Depreciation and Amortization	$125.2	$25.6	$0.4	$151.2
Operating Income (Loss)	$275.9	$119.0	($3.2)	$391.7
Equity in Earnings of Unconsolidated Affiliates	$30.3	$ -	$ -	$30.3
Interest Expense, net	$59.7	$17.9	$24.8	$102.4
Income Tax Expense (Benefit)	$94.3	$40.5	($15.8)	$119.0
Income from Discontinued Operations, Net of Tax	$0.7	$ -	$1.2	$1.9
Net Income (Loss)	$168.2	$60.5	($10.3)	$218.4
Capital Expenditures	$295.9	$82.4	$0.8	$379.1
Total Assets (c)	$11,660.7	$2,923.9	($1,891.1)	$12,693.5

	Six Months Ended			
June 30, 2009				
Operating Revenues (b)	$2,220.8	$80.8	($77.6)	$2,224.1
Depreciation and Amortization	$155.8	$14.5	$0.3	$170.6
Operating Income (Loss)	$304.2	$58.7	($3.0)	$359.9
Equity in Earnings of Unconsolidated Affiliates	$28.7	$ -	$ -	$28.7
Interest Expense, net	$59.6	$8.2	$12.8	$80.6
Income Tax Expense (Benefit)	$103.2	$21.9	($7.7)	$117.4
Income (Loss) from Discontinued Operations, Net of Tax	$0.9	$ -	($0.1)	$0.8
Net Income (Loss)	$183.8	$30.5	($9.1)	$205.2

Capital Expenditures	$273.2	$84.7	$5.5	$363.4
Total Assets (c)	$10,572.6	$2,613.8	($888.1)	$12,298.3

(a) 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 of $76.2 million and $41.6 million for the three months ended June 30, 2010 and 2009, respectively, and $136.2 million and $77.8 million for the six months ended June 30, 2010 and 2009, respectively, is included in Operating Revenues.

(c) An elimination of $1,820.8 million and $892.4 million is included in Total Assets at June 30, 2010 and 2009, respectively, for PTF-related activity between We Power and Wisconsin Electric.

12 -- 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 two tolling and purchased power agreements with third parties which represent variable interests. We account for one of these agreements, with an independent power producer, as an operating lease. The agreement has a remaining term of three years. We have examined the risks of the entity including the impact of operations and maintenance, dispatch, financing, fuel costs, remaining useful life and other factors, and have determined that we are not the primary beneficiary of this entity. We have concluded that we do not have the power to direct the activities that would most significantly affect the economic performance of the entity over its remaining life.

We also have a purchased power agreement for 236 MW of firm capacity from a gas-fired cogeneration facility, which we account for as a capital lease. The agreement includes no minimum energy requirements over the remaining term of 13 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 $392.0 million of required payments over the remaining term of these agreements. We believe that the required lease payments under these contracts will continue to be recoverable in rates. Total capacity and lease payments under these contracts for the six months ended June 30, 2010 were $31.0 million. Our maximum exposure to loss is limited to the capacity payments under the contracts.

13 -- COMMITMENTS AND CONTINGENCIES

Environmental Matters:

We periodically review our exposure for remediation costs as evidence becomes available indicating that our liability has changed. Given current information, 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.

Divestitures:

Over the past several years, we have sold various businesses and assets. In connection with these sales, we have agreed to provide the respective buyers with customary indemnification provisions including, but not limited to, certain environmental, asbestos and product liability matters. In addition, pursuant to the sale of Point Beach, we have agreed to indemnification provisions customary to transactions involving the sale of nuclear assets. We have established reserves as deemed appropriate for these indemnification provisions.

Income Taxes:

During the second quarter 2010, our federal unrecognized tax benefits decreased by $12.3 million as the result of payment of a tax obligation for a prior year.

14 -- SUPPLEMENTAL CASH FLOW INFORMATION

During the six months ended June 30, 2010, we paid $101.1 million in interest, net of amounts capitalized, and $116.7 million in income taxes, net of refunds. During the six months ended June 30, 2009, we paid $79.8 million in interest, net of amounts capitalized, and $1.3 million in income taxes, net of refunds.

As of June 30, 2010 and 2009, the amount of accounts payable related to capital expenditures was $24.4 million and $40.2 million, respectively.

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

RESULTS OF OPERATIONS -- THREE MONTHS ENDED JUNE 30, 2010

CONSOLIDATED EARNINGS

The following table compares our operating income by business segment and our net income during the second quarter of 2010 with the second quarter of 2009 including favorable (better (B)) or unfavorable (worse (W)) variances:

	Three Months Ended June 30		
	2010	B (W)	2009
	(Millions of Dollars)		
Utility Energy Segment	$97.8	$8.4	$89.4
Non-Utility Energy Segment	66.9	36.1	30.8
Corporate and Other	(1.4)	0.4	(1.8)
Total Operating Income	163.3	44.9	118.4
Equity in Earnings of Transmission Affiliate	15.1	0.7	14.4
Other Income, net	9.7	2.3	7.4
Interest Expense, net	53.0	(13.2)	39.8
Income from Continuing Operations Before Income Taxes	135.1	34.7	100.4
Income Taxes	47.6	(10.2)	37.4
Income from Continuing Operations	87.5	24.5	63.0
Income from Discontinued Operations, Net of Tax	1.2	0.5	0.7
Net Income	$88.7	$25.0	$63.7
Diluted Earnings Per Share	$0.75	$0.21	$0.54

UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

Our utility energy segment contributed $97.8 million of operating income during the second quarter of 2010, an increase of $8.4 million, or 9.4%, compared with the second quarter of 2009. The following table summarizes the operating income of this segment between the comparative quarters:

	Three Months Ended June 30		
Utility Energy Segment	2010	B (W)	2009
		(Millions of Dollars)	
Operating Revenues			
Electric	$701.7	$57.5	$644.2

Gas	172.1	(9.4)	181.5
Other	6.7	(0.6)	7.3
Total Operating Revenues	880.5	47.5	833.0
Fuel and Purchased Power	259.6	(5.9)	253.7
Cost of Gas Sold	95.8	6.3	102.0
Gross Margin	525.1	47.8	477.4
Other Operating Expenses			
Other Operation and Maintenance	385.7	(48.4)	337.3
Depreciation and Amortization	62.7	15.4	78.1
Property and Revenue Taxes	26.1	1.4	27.6
Total Operating Expenses	829.9	(31.2)	798.7
Amortization of Gain	47.2	(7.9)	55.1

Electric Utility Revenues and Sales

The following table compares electric utility operating revenues and MWh sales by customer class during the second quarter of 2010 with the second quarter of 2009:

	Three Months Ended June 30					
	Electric Revenues			MWh Sales		
Electric Utility Operations	2010	B (W)	2009	2010	B (W)	2009
	(Millions of Dollars)			(Thousands)		
Customer Class						
Residential	$251.4	$23.4	$228.0	1,873.9	32.1	1,841.8
Small Commercial/Industrial	230.4	20.8	209.6	2,146.3	96.1	2,050.2
Large Commercial/Industrial	171.3	27.3	144.0	2,458.6	307.5	2,151.1
Other-Retail	5.0	0.1	4.9	35.8	(0.8)	36.6
Total Retail	658.1	71.6	586.5	6,514.6	434.9	6,079.7
Wholesale-Other	30.1	3.0	27.1	400.0	93.1	306.9
Resale-Utilities	8.1	2.3	5.8	310.7	96.2	214.5
Other Operating Revenues	5.4	(19.4)	24.8	-	-	-
Total	$701.7	$57.5	$644.2	7,225.3	624.2	6,601.1

Weather -- Degree Days (a)

Heating (949 Normal)	671	(275)	946
Cooling (170 Normal)	208	74	134

(a) 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 $57.5 million, or 8.9%, when compared to the second quarter of 2009. The most significant factors that caused the change in revenues were:

- Net pricing increases totaling $30.8 million related to Wisconsin and Michigan rate orders that became effective in 2010. For information on these rate orders, see Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters.
- Favorable weather that increased electric revenues by an estimated $19.4 million as compared to the second quarter of 2009.
- Net economic growth that increased electric revenues by an estimated $12.7 million as compared to the second quarter of 2009.
- 2010 pricing increases totaling approximately $7.9 million, reflecting the reduction of Point Beach bill credits to retail customers.

As measured by cooling degree days, the second quarter of 2010 was 55.2% warmer than the same period in 2009 and 22.4% warmer than normal. Collectively, retail sales to our residential and small commercial and industrial customers, who are more weather sensitive, increased by 3.3%. Sales to our large commercial and industrial customers increased by 14.3% during the second quarter of 2010 as compared to the same period in 2009 primarily because of an improving economy. Electric sales to our largest customers, two iron ore mines, which represent approximately 6.5% of our annual sales, increased significantly for the quarter. If these sales are excluded, sales to our large commercial and industrial customers increased by 7.1% for the second quarter of 2010 as compared to the second quarter of 2009. The $19.4 million decline in Other Operating Revenues primarily relates to regulatory amortizations during the second quarter of 2010 as compared to the same period in 2009, and a one-time entry in the second quarter of 2009 related to the expected recovery of MISO costs.

Fuel and Purchased Power

Our fuel and purchased power costs increased by $5.9 million, or 2.3%, when compared to the second quarter of 2009. This increase was primarily caused by the 9.5% increase in total MWh sales, partially offset by a 6.5% decrease in the average cost/MWh between periods. The lower average cost/MWh was primarily caused by a 35.6% increase in generation from our lower cost coal units.

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 2010 with the second quarter of 2009. 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 decreased by $9.4 million, or 5.2%, primarily because of lower natural gas prices and milder weather.

Three Months Ended June 30

	2010	B (W)	2009
	(Millions of Dollars)		
Gas Operating Revenues	$172.1	($9.4)	$181.5
Cost of Gas Sold	95.8	6.2	102.0
Gross Margin	$76.3	($3.2)	$79.5

The following table compares gas utility gross margin and natural gas therm deliveries by customer class during the second quarter of 2010 with the second quarter of 2009:

	Three Months Ended June 30					
	Gross Margin			Therm Deliveries		
Gas Utility Operations	2010	B (W)	2009	2010	B (W)	2009
	(Millions of Dollars)			(Millions)		
Customer Class						
Residential	$48.2	($3.2)	$51.4	91.1	(20.4)	111.5
Commercial/Industrial	13.8	(1.3)	15.1	51.8	(12.3)	64.1
Interruptible	0.5	0.1	0.4	3.9	-	3.9
Total Retail	62.5	(4.4)	66.9	146.8	(32.7)	179.5
Transported Gas	11.1	1.0	10.1	190.1	(9.2)	199.3
Other	2.7	0.2	2.5	-	-	-
Total	$76.3	($3.2)	$79.5	336.9	(41.9)	378.8
Weather -- Degree Days (a)						
Heating (949 Normal)				671	(275)	946

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

Our gas margins decreased by $3.2 million, or approximately 4.0%, when compared to the second quarter of 2009, primarily because of a decline in sales volumes as a result of milder weather during the second quarter of 2010 that reduced heating loads. As measured by heating degree days, the second quarter of 2010 was 29.1% warmer than the same period in 2009 and 29.3% warmer than normal.

Other Operation and Maintenance Expense

Our other operation and maintenance expense increased by $48.4 million, or approximately 14.3%, when compared to the second quarter of 2009. The 2010 PSCW rate case order allowed for pricing increases related to regulatory items including PTF lease costs, bad debt expense and amortization of other deferred costs. We estimate that these items were approximately $21.1 million higher in the second quarter of 2010 as compared to the same period in 2009. In addition, operation and maintenance expenses at our power plants increased approximately $17.2 million primarily because of the operation of OC 1, which was placed in service in February 2010, and higher maintenance costs at our other power plants.

Depreciation and Amortization Expense

Our depreciation and amortization expense decreased by $15.4 million, or approximately 19.7%, when compared to the second quarter of 2009, primarily because of new depreciation rates that were implemented in connection with the 2010 PSCW rate case order. The new depreciation rates generally reflect longer lives for our utility assets.

Amortization of Gain

In connection with the September 2007 sale of Point Beach, we reached an agreement with our regulators to allow for the net gain on the sale to be used for the benefit of our customers. The majority of the benefits are being returned to customers in the form of bill credits. The net gain was originally recorded as a regulatory liability, and it is being amortized to the income statement as we issue bill credits to customers. When the bill credits are issued to customers, we transfer cash from the restricted accounts to the unrestricted accounts, adjusted for taxes. During the second quarter of 2010 and 2009, the Amortization of Gain was $47.2 million and $55.1 million, respectively.

NON-UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

Our non-utility energy segment consists primarily of our PTF units (PWGS 1, PWGS 2, OC 1 and OC 2). PWGS 1 and 2 were placed in service in July 2005 and May 2008, respectively. The common facilities associated with the Oak Creek expansion consist of the water intake system, which was placed in service in January 2009, and the coal handling system and other smaller assets, which were placed in service prior to January 2009. OC 1 was placed in service in February 2010. We expect OC 2 to be placed in service during the fourth quarter of 2010; the guaranteed in-service date for OC 2 is November 28, 2010.

The table below reflects a full quarter's earnings for 2010 and 2009 for PWGS 1 and 2 and the common facilities for the Oak Creek expansion. It also reflects a full quarter's earnings for 2010 for OC 1. This segment reflects the lease revenues on the new units, 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.

	Quarter Ended June 30, 2010 (Millions of Dollars)			
	Port Washington	Oak Creek Expansion	All Other	Total
Operating Revenues	$26.5	$56.0	$3.9	$86.4
Operation and Maintenance Expense	0.5	2.7	2.5	5.7
Depreciation Expense	4.9	8.5	0.4	13.8
Operating Income	$21.1	$44.8	$1.0	$66.9

	Quarter Ended June 30, 2009 (Millions of Dollars)			
	Port Washington	Oak Creek Expansion	All Other	Total
Operating Revenues	$26.5	$14.4	$3.2	$44.1
Operation and Maintenance Expense	0.6	3.4	2.1	6.1
Depreciation Expense	4.9	1.9	0.4	7.2
Operating Income	$21.0	$9.1	$0.7	$30.8

CONSOLIDATED OTHER INCOME, NET

Other income, net increased by approximately $2.3 million, or 31.0%, when compared to the second quarter of 2009 primarily because of an increase in Allowance for Funds Used During Construction (AFUDC) related to the construction of our Oak Creek Air Quality Control System (AQCS) project during the second quarter of 2010 as compared to the same period in 2009.

CONSOLIDATED INTEREST EXPENSE, NET

	Three Months Ended June 30	
Interest Expense	2010	2009
	(Millions of Dollars)	
Gross Interest Costs	$65.1	$58.8
Less: Capitalized Interest	12.1	19.0
Interest Expense, net	$53.0	$39.8

Our gross interest costs increased by $6.3 million, or 10.7%, during the second quarter of 2010, primarily because of higher long-term debt balances compared to the same period in 2009. In February 2010, we issued $530 million of long-term debt in connection with the commercial operation of OC 1 and used the net proceeds to repay short-term debt incurred during construction. Our capitalized interest decreased by $6.9 million primarily because we stopped capitalizing interest on OC 1 when it was placed in service in February 2010. As a result, our net interest expense increased by $13.2 million, or 33.2%, as compared to the second quarter of 2009.

CONSOLIDATED INCOME TAXES

For the second quarter of 2010, our effective tax rate applicable to continuing operations was 35.2% compared to 37.2% for the second quarter of 2009. For additional information, see Note H -- Income Taxes in our 2009 Annual Report on Form 10-K.

RESULTS OF OPERATIONS -- SIX MONTHS ENDED JUNE 30, 2010

CONSOLIDATED EARNINGS

The following table compares our operating income by business segment and our net income during the first six months of 2010 with the first six months of 2009 including favorable (better (B)) or unfavorable (worse (W)) variances:

	Six Months Ended June 30		
	2010	B (W)	2009
	(Millions of Dollars)		
Utility Energy Segment	$275.9	($28.3)	$304.2
Non-Utility Energy Segment	119.0	60.3	58.7
Corporate and Other	(3.2)	(0.2)	(3.0)
Total Operating Income	391.7	31.8	359.9
Equity in Earnings of Transmission Affiliate	30.3	1.6	28.7
Other Income, net	15.9	2.1	13.8
Interest Expense, net	102.4	(21.8)	80.6
Income from Continuing Operations Before Income Taxes	335.5	13.7	321.8
Income Taxes	119.0	(1.6)	117.4
Income from Continuing Operations	216.5	12.1	204.4
Income from Discontinued Operations, Net of Tax	1.9	1.1	0.8
Net Income	$218.4	$13.2	$205.2
Diluted Earnings Per Share	$1.85	$0.11	$1.74

UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

Our utility energy segment contributed $275.9 million of operating income during the first six months of 2010, a decrease of $28.3 million, or 9.3%, compared with the first six months of 2009. The following table summarizes the operating income of this segment between the comparative periods:

	Six Months Ended June 30		
Utility Energy Segment	2010	B (W)	2009

		(Millions of Dollars)	
Operating Revenues			
Electric	$1,405.5	$75.6	$1,329.9
Gas	696.3	(172.2)	868.5
Other	21.6	(0.7)	22.3
Total Operating Revenues	2,123.4	(97.3)	2,220.7
Fuel and Purchased Power	538.2	(18.4)	519.8
Cost of Gas Sold	451.6	153.1	604.7
Gross Margin	1,133.6	37.4	1,096.2
Other Operating Expenses			
Other Operation and Maintenance	776.6	(76.2)	700.4
Depreciation and Amortization	125.2	30.6	155.8
Property and Revenue Taxes	52.5	2.6	55.1
Total Operating Expenses	1,944.1	91.7	2,035.8
Amortization of Gain	96.6	(22.7)	119.3
Operating Income	$275.9	($28.3)	$304.2

The decrease in Operating Income for the six months ended June 30, 2010 as compared to the same period in 2009 was primarily caused by unfavorable recoveries of revenues associated with fuel and purchased power and milder winter weather in 2010. During the first six months of 2010, we experienced unfavorable fuel recoveries of approximately $30 million. During the same period in 2009, we experienced favorable fuel recoveries of approximately $24 million. Although we received a fuel order from the PSCW in March 2010 allowing us to increase our rates on an interim basis, we expect to be in an unfavorable fuel recovery position for 2010. For additional information on the fuel order, see Factors Affecting Results, Liquidity and Capital Resources - Utility Rates and Regulatory Matters - 2010 Fuel Recovery Request.

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 2010 with the first six months of 2009:

	Six Months Ended June 30					
	Electric Revenues			MWh Sales		
Electric Utility Operations	2010	B (W)	2009	2010	B (W)	2009
	(Millions of Dollars)			(Thousands)		
Customer Class						
Residential	$512.8	$27.4	$485.4	3,875.2	(39.7)	3,914.9
Small Commercial/Industrial	447.5	15.8	431.7	4,294.0	21.9	4,272.1
Large Commercial/Industrial	326.4	40.8	285.6	4,822.9	479.6	4,343.3
Other - Retail	10.8	0.3	10.5	76.2	(1.2)	77.4

Total Retail	1,297.5	84.3	1,213.2	13,068.3	460.6	12,607.7
Wholesale - Other	71.5	9.5	62.0	1,036.3	154.5	881.8
Resale - Utilities	23.4	(0.4)	23.8	676.6	(15.0)	691.6
Other Operating Revenues	13.1	(17.8)	30.9	-	-	-
Total	$1,405.5	$75.6	$1,329.9	14,781.2	600.1	14,181.1
Weather -- Degree Days (a)						
Heating (4,193 Normal)				3,815	(589)	4,404
Cooling (171 Normal)				208	74	134

(a) 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 $75.6 million, or 5.7%, when compared to the first six months of 2009. The most significant factors that caused the change in revenues were:

- Net pricing increases totaling $37.2 million related to Wisconsin and Michigan rate orders that became effective in 2010. For information on these rate orders, see Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters.

- 2010 pricing increases totaling approximately $22.7 million, reflecting the reduction of Point Beach bill credits to retail customers.
- Net economic growth that increased electric revenues by an estimated $17.8 million as compared to the first six months of 2009.
- Favorable weather that increased electric revenues by an estimated $6.1 million as compared to the first six months of 2009.

Sales to our large commercial and industrial customers increased by 11.0% during the first six months of 2010 as compared to the same period in 2009 primarily because of an improving economy. However, electric sales to our largest customers, two iron ore mines, which represent approximately 6.5% of our annual sales, increased significantly for the first six months of the year. If these sales are excluded, sales to our large commercial and industrial customers increased by 3.8% for the first six months of 2010 as compared to the first six months of 2009. The $17.8 million decline in Other Operating Revenues primarily relates to regulatory amortizations during the first six months of 2010 as compared to the same period in 2009.

Fuel and Purchased Power

Our fuel and purchased power costs increased by $18.4 million, or 3.5%, when compared to the first six months of 2009. This increase was primarily caused by the 4.2% increase in MWh sales, partially offset by a 0.6% decrease in the average cost/MWh between periods. The lower average cost/MWh was primarily caused by an 11.5% increase in generation from our lower cost coal units, partially offset by a 5% increase in coal and transportation costs between periods.

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 2010 with the first six months of 2009. 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 decreased by $172.2 million, or 19.8%, primarily because of lower natural gas prices and milder weather.

	Six Months Ended June 30		
	2010	B (W)	2009
	(Millions of Dollars)		
Gas Operating Revenues	$696.3	($172.2)	$868.5
Cost of Gas Sold	451.6	153.1	604.7
Gross Margin	$244.7	($19.1)	$263.8

The following table compares gas utility gross margin and natural gas therm deliveries by customer class during the first six months of 2010 with the first six months of 2009:

	Six Months Ended June 30					
	Gross Margin			Therm Deliveries		
Gas Utility Operations	2010	B (W)	2009	2010	B (W)	2009
	(Millions of Dollars)			(Millions)		
Customer Class						
Residential	$157.2	($12.2)	$169.4	439.9	(61.6)	501.5
Commercial/Industrial	54.6	(7.9)	62.5	250.8	(44.6)	295.4
Interruptible	1.2	0.1	1.1	11.4	0.4	11.0
Total Retail	213.0	(20.0)	233.0	702.1	(105.8)	807.9
Transported Gas	26.5	1.2	25.3	474.5	2.3	472.2
Other	5.2	(0.3)	5.5	-	-	-
Total	$244.7	($19.1)	$263.8	1,176.6	(103.5)	1,280.1
Weather -- Degree Days (a)						
Heating (4,193 Normal)				3,815	(589)	4,404

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

Our gas margins decreased by $19.1 million, or approximately 7.2%, when compared to the first six months of 2009,primarily because of a decline in sales volumes as a result of milder winter weather during the first six months of 2010 as compared to the first six months of 2009. As measured by heating degree days, the first six months of 2010 were 13.4% warmer than the same period in 2009 and 9.0% warmer than normal.

Other Operation and Maintenance Expense

Our other operation and maintenance expense increased by approximately $76.2 million, or 10.9%, when compared to the first six months of 2009. The 2010 PSCW rate case order allowed for pricing increases related to regulatory items including PTF lease costs, bad debt expense and amortization of other deferred costs. We estimate that these items were approximately $43.4 million higher in the first six months of 2010 as compared to the same period in 2009. In addition, operation and maintenance expenses at our power plants increased approximately $24.5 million primarily because of the operation of OC 1, which was placed in service in February 2010, and higher maintenance costs at our other power plants.

Depreciation and Amortization Expense

Our depreciation and amortization expense decreased by $30.6 million, or approximately 19.6%, when compared to the first six months of 2009, primarily because of new depreciation rates that were implemented in connection with the 2010 PSCW rate case order. The new depreciation rates generally reflect longer lives for our utility assets.

Amortization of Gain

During the first six months of 2010 and 2009, the Amortization of Gain was $96.6 million and $119.3 million, respectively. For 2010, we expect to see a reduction in the Amortization of Gain of approximately $34.6 million as compared to 2009 because of the scheduled decrease in Point Beach bill credits. We expect that all remaining Point Beach bill credits will be issued by the end of 2010.

NON-UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

The table below reflects six months of earnings for 2010 and 2009 for PWGS 1 and 2 and the common facilities for the Oak Creek expansion. It also reflects five months of earnings in 2010 for OC 1. This segment reflects the lease revenues on the new units, 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, 2010 (Millions of Dollars)			
	Port Washington	Oak Creek Expansion	All Other	Total
Operating Revenues	$52.5	$95.4	$4.1	$152.0
Operation and Maintenance Expense	0.6	3.4	3.4	7.4
Depreciation Expense	9.9	14.9	0.8	25.6
Operating Income (Loss)	$42.0	$77.1	($0.1)	$119.0

	Six Months Ended June 30, 2009 (Millions of Dollars)			
	Port Washington	Oak Creek Expansion	All Other	Total
Operating Revenues	$52.7	$24.8	$3.3	$80.8
Operation and Maintenance Expense	0.7	4.1	2.8	7.6
Depreciation Expense	9.9	3.8	0.8	14.5
Operating Income (Loss)	$42.1	$16.9	($0.3)	$58.7

CONSOLIDATED OTHER INCOME, NET

Other income, net increased by approximately $2.1 million, or 15.2%, when compared to the first six months of 2009. This increase primarily relates to increased AFUDC related to large construction projects during the first six months of 2010 as compared to the same period in 2009.

CONSOLIDATED INTEREST EXPENSE, NET

Interest Expense	Six Months Ended June 30	
	2010	2009
	(Millions of Dollars)	
Gross Interest Costs	$128.2	$118.8
Less: Capitalized Interest	25.8	38.2
Interest Expense, net	$102.4	$80.6

Our gross interest costs increased by $9.4 million, or 7.9%, during the first six months of 2010, primarily because of higher long-term debt balances compared to the same period in 2009. In February 2010, we issued $530 million of long-term debt in connection with the commercial operation of OC 1 and used the net proceeds to repay short-term debt incurred during construction. Our capitalized interest decreased by $12.4 million primarily because we stopped capitalizing interest on OC 1 when it was placed in service in February 2010. As a result, our net interest expense increased by $21.8 million, or 27.0%, as compared to the first six months of 2009.

CONSOLIDATED INCOME TAXES

For the first six months of 2010, our effective tax rate applicable to continuing operations was 35.5% compared to 36.5% for the first six months of 2009. For additional information, see Note H -- Income Taxes in our 2009 Annual Report on Form 10-K. We expect our 2010 annual effective tax rate to be between 35% and 36%.

LIQUIDITY AND CAPITAL RESOURCES

CASH FLOWS

The following summarizes our cash flows from continuing operations during the first six months of 2010 and 2009:

	Six Months Ended June 30	
Wisconsin Energy Corporation	2010	2009
	(Millions of Dollars)	
Cash Provided by (Used in)		
Operating Activities	$423.7	$231.0
Investing Activities	($275.3)	($304.8)
Financing Activities	($158.1)	$53.9

Operating Activities

Cash provided by operating activities was $423.7 million during the six months ended June 30, 2010, which was $192.7 million higher than the same period in 2009. The largest item which led to the increase in cash from operations related to $289.3 million of contributions to our benefit plans in the first six months of 2009. No such contributions were required in the first six months of 2010.

Investing Activities

Cash used in investing activities was $275.3 million during the six months ended June 30, 2010, which was $29.5 million lower than the same period in 2009, primarily because of a $48.7 million increase in

proceeds from assets sales resulting from the sale of Edison Sault. Partially offsetting this increase, our capital expenditures increased by $15.7 million during the first six months of 2010 as compared to the same period in 2009, primarily because of increased expenditures related to the beginning of construction of our Glacier Hills Wind Park.

Financing Activities

Cash used in financing activities during the six months ended June 30, 2010 was $158.1 million, compared to cash provided by financing activities during the same period in 2009 of $53.9 million. Our operating cash flows during the

first six months of 2010 allowed us to increase our dividends and reduce our net debt levels. During the first six months of 2010, we paid approximately $93.5 million in cash dividends and decreased our debt levels by a net amount of approximately $38.2 million.

During the first six months of 2010, we received proceeds of $43.2 million related to the exercise of stock options, compared with $6.3 million during the same period in 2009. Instead of issuing new shares for these stock options, we instructed our plan agent to purchase common stock in the open market at a cost of $68.9 million, compared with $10.5 million during the first six months of 2009. This cost is included in Purchase of common stock on our Consolidated Condensed Statements of Cash Flows.

CAPITAL RESOURCES AND REQUIREMENTS

Working Capital

As of June 30, 2010, our current liabilities exceeded our current assets by approximately $379.7 million. This negative working capital balance is a result of financing the construction of OC 2 with significant amounts of short-term debt and an increase in long-term debt due currently. We anticipate financing a portion of the construction costs of OC 2 with long-term debt upon commercial operation of OC 2. We expect this transaction will significantly improve our working capital position.

Capital Resources

We anticipate meeting our capital requirements during the remaining six months of 2010 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, including the Oak Creek financing discussed under working capital above. Beyond 2010, we anticipate meeting our capital requirements through internally generated funds supplemented, when required, by short-term borrowings and the issuance of debt securities.

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, 2010, we had approximately $1.6 billion of available, undrawn lines under our bank back-up credit facilities, and approximately $520.4 million of short-term debt outstanding on a consolidated basis that was supported by the available lines of credit.

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, 2010:

Company	Total Facility	Letters of Credit	Credit Available	Facility Expiration
		(Millions of Dollars)		
Wisconsin Energy	$857.5	$1.1	$856.4	April 2011
Wisconsin Electric	$476.4	$2.4	$474.0	March 2011
Wisconsin Gas	$285.8	$ -	$285.8	March 2011

The following table shows our capitalization structure as of June 30, 2010, as well as an adjusted capitalization structure that we believe is more 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	$3,677.1	$3,927.1
Preferred Stock of Subsidiary	30.4	30.4
Long-Term Debt (including current maturities)	4,435.9	4,185.9
Short-Term Debt	520.4	520.4
Total Capitalization	$8,663.8	$8,663.8
Total Debt	$4,956.3	$4,706.3
Ratio of Debt to Total Capitalization	57.2%	54.3%

Included in Long-Term Debt on our Consolidated Condensed Balance Sheet as of June 30, 2010 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, 2010, the repurchased bonds were still outstanding, but were reported as a reduction in our consolidated long-term debt because they are held by Wisconsin Electric. Depending on market conditions and other factors, Wisconsin Electric may change the method used to

determine the interest rate on the bonds and have them remarketed to third parties.

Access to capital markets at a reasonable cost is determined in large part by credit quality. Any change in ratings or ratings outlooks may impact our cost of capital and access to the capital markets. In July 2010, S&P affirmed the ratings of Wisconsin Energy, Wisconsin Electric, Wisconsin Gas, Wisconsin Energy Capital Corporation (WECC) and Elm Road Generating Station Supercritical, LLC (ERGSS) and the stable ratings outlooks assigned to each company.

In June 2010, Fitch affirmed the ratings of Wisconsin Energy, Wisconsin Electric, Wisconsin Gas, WECC and ERGSS. Fitch also revised the ratings outlooks assigned to Wisconsin Energy, Wisconsin Electric, WECC and ERGSS from negative to stable, and affirmed the stable ratings outlook of Wisconsin Gas. Prior to these actions, Fitch revised its ratings guidelines on corporate and utility hybrid and preferred securities. These ratings guideline revisions reduced the ratings of Wisconsin Energy's Unsecured Junior Notes and Wisconsin Electric's Preferred Stock one notch from BBB+ to BBB and from A to A -, respectively.

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 if it decides that the circumstances warrant the change.

Capital Requirements

Our estimated 2010, 2011 and 2012 capital expenditures reflecting actual costs through June 30, 2010 are as follows:

Capital Expenditures	2010	2011	2012
	(Millions of Dollars)		
Utility			
Renewable	$96.8	$384.7	$179.3
Environmental	229.4	193.9	80.7
Base Spending	368.6	404.5	446.3
Total Utility	694.8	983.1	706.3
We Power	120.1	10.7	30.5
Other	2.3	5.1	5.1
Total	$817.2	$998.9	$741.9

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

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 continue to 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 -- Guarantees and Note 12 -- 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 $21.7 billion as of June 30, 2010 compared with $21.5 billion as of December 31, 2009. Our total contractual obligations and other commercial commitments as of June 30, 2010 increased compared with December 31, 2009 primarily because of long-term debt issued in February 2010 in connection with the commercial operation of OC 1. This increase was partially offset by periodic payments made in the ordinary course of business during the first six months of 2010.

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 2009 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

Under our PTF strategy, we expect to meet a significant portion of our future generation needs through the construction of the PWGS and the Oak Creek expansion by We Power. We Power leases the PWGS and

OC 1 units to Wisconsin Electric under long-term leases, and Wisconsin Electric is currently recovering the lease payments in its electric rates. When OC 2 goes into service, we expect Wisconsin Electric to also recover those lease payments in rates. See Factors Affecting Results, Liquidity and Capital Resources -- Power the Future in Item 7 of our 2009 Annual Report on Form 10-K for additional information on PTF.

Oak Creek Expansion:

OC 1 was placed into service in February 2010. We expect OC 2 to be placed in service during the fourth quarter of 2010; the guaranteed in-service date for OC 2 is November 28, 2010.

UTILITY RATES AND REGULATORY MATTERS

2010 Rate Case:

In March 2009, Wisconsin Electric and Wisconsin Gas initiated rate proceedings with the PSCW. Wisconsin Electric initially asked the PSCW to approve a rate increase for its Wisconsin retail electric customers of approximately $76.5 million, or 2.8%, and a rate increase for its natural gas customers of approximately $22.1 million, or 3.6%. In addition, Wisconsin Electric requested increases of approximately $1.4 million, or 5.8%, and approximately $1.3 million, or 6.8%, for its Milwaukee Downtown (Valley) steam utility customers and Milwaukee County steam utility customers, respectively. Wisconsin Gas asked the PSCW to approve a rate increase for its natural gas customers of approximately $38.9 million, or 4.6%.

In July 2009, Wisconsin Electric filed supplemental testimony with the PSCW updating its rate increase request for retail electric customers to reflect the impact of lower sales as a result of the decline in the economy. The effect of the change resulted in Wisconsin Electric increasing its request from $76.5 million to $126.0 million.

In December 2009, the PSCW authorized rate adjustments related to Wisconsin Electric's and Wisconsin Gas' requests to increase electric, natural gas and steam rates. The PSCW approved the following rate adjustments:

- An increase of approximately $85.8 million (3.35%) in retail electric rates for Wisconsin Electric, which included a decrease in base fuel revenues of approximately $111.0 million, or a fuel rate component decrease of 13.8%;
- A decrease of approximately $2.0 million (0.35%) for natural gas service for Wisconsin Electric;
- An increase of approximately $5.7 million (0.70%) for natural gas service for Wisconsin Gas; and
- A decrease of approximately $0.4 million (1.65%) for Wisconsin Electric's Valley steam utility customers and a decrease of approximately $0.1 million (0.47%) for its Milwaukee County steam utility customers.

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

The PSCW also made, among others, the following determinations:

- New depreciation rates were incorporated into the new base rates approved in the rate case;
- Certain regulatory assets that were scheduled to be fully amortized over the next four years are to instead be amortized over the next eight years; and
- Wisconsin Electric will continue to receive AFUDC on 100% of Construction Work in Progress for the environmental control projects at our Oak Creek Power Plant and at Edgewater Generating Unit 5, and on the Glacier Hills Wind Park.

2010 Michigan Rate Increase Request:

In July 2009, Wisconsin Electric filed a $42 million rate increase request with the MPSC, primarily to recover the costs of PTF projects. Michigan law allows utilities, upon the satisfaction of certain conditions, to self-implement a rate increase request, subject to refund with interest. In December 2009, the MPSC approved Wisconsin Electric's modified self-implementation plan to increase electric rates in Michigan by approximately $12 million, effective upon commercial operation of OC 1, which occurred on February 2, 2010. On July 1, 2010, the MPSC issued the final order, approving an additional increase of $11.5 million effective July 2, 2010. The combined

total increase, which is subject to appeal, is $23.5 million, or 14.2%. The time period for appeal on this decision is 30 days from the effective date of the order.

2010 Fuel Recovery Request:

On February 19, 2010, Wisconsin Electric filed a $60.5 million rate increase request with the PSCW to recover forecasted increases in fuel and purchased power costs. The increase in fuel and purchased power costs is being driven primarily by increases in the price of natural gas compared to the forecasted prices included in the 2010 PSCW rate case order, changes in the timing of plant outages and increased MISO costs. On March 25, 2010, the PSCW approved an annual increase of $60.5 million in Wisconsin retail electric rates on an interim basis. The increased rates were effective March 25, 2010. The revenues that we collect are subject to refund with interest at a rate of 10.4%. We expect PSCW review and final approval by the end of 2010.

Wisconsin Electric - Wisconsin Gas Merger:

On April 1, 2010, Wisconsin Electric and Wisconsin Gas filed a joint application with the PSCW to merge Wisconsin Gas into Wisconsin Electric. If approved by the PSCW, we anticipate the merger will be effective January 1, 2011. We do not expect the merger to have any material effect on our results of operations. In addition, we do not expect the merger request to have any negative rate impact on customers.

Wisconsin Fuel Rules:

Within the state of Wisconsin, Wisconsin Electric operates under a fuel cost adjustment clause for fuel and purchased power costs associated with the generation and delivery of electricity and purchase power contracts. Embedded within its base rates is an amount to recover fuel costs. Under the current fuel rules, no adjustments are made to rates as long as fuel and purchased power costs are expected to be within a band of the costs embedded in current rates for the 12-month period ending December 31. If, however, annual fuel costs are expected to fall outside of the band, and actual costs fall outside of established fuel bands, then we may file for a change in fuel recoveries on a prospective basis.

In June 2006, the PSCW opened a docket (01-AC-224) to consider revisions to the existing fuel rules (Chapter PSC 116). In April 2010, the Wisconsin legislature passed the Fuel Rule Bill. The Governor of Wisconsin signed the bill in May 2010. Under this bill, the PSCW will be required to defer, for subsequent rate recovery or refund, any under-collection or over-collection of fuel costs that are outside of the utility's symmetrical fuel cost tolerance. As part of the new rules, the PSCW would need to establish the size of the symmetrical band and the definition of recoverable fuel and purchased power costs. We expect the new fuel rules to be effective January 1, 2011.

Renewable Energy Portfolio:

In July 2008, we completed the purchase of rights to a new wind farm site in Central Wisconsin, Glacier Hills Wind Park, and filed a request for a Certificate of Public Convenience and Necessity (CPCN) with the PSCW in October 2008. The PSCW approved the CPCN in January 2010. We currently expect to install 90 wind turbines with a total generating capacity of approximately 162 MW. This project is expected to cost between $360 and $370 million, excluding AFUDC. Construction commenced in May 2010, and we anticipate 2012 will be the first full year of operation.

In September 2009, we announced plans to construct a biomass-fueled power plant at Domtar Corporation's Rothschild, Wisconsin paper mill site. Wood waste and wood shavings will be used to produce approximately 50 MW of renewable electricity and will also support Domtar's sustainable papermaking operations. We believe the biomass plant will be eligible for either the federal production tax credit or the federal 30% investment tax credit. We currently expect to invest approximately $255 million in the plant and for it to be completed during the fall of 2013, subject to regulatory and other approvals. In March 2010, we filed a request for a Certificate of Authority for the project with the PSCW. We expect the PSCW to approve the Certificate of Authority by the end of 2010.

See Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters in Item 7 of our 2009 Annual Report on Form 10-K for additional information regarding our utility rates and other regulatory matters.

ELECTRIC TRANSMISSION AND ENERGY MARKETS

MISO:

As part of MISO, a market-based platform was developed for valuing transmission congestion premised upon the Locational Marginal Pricing (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 was completed for the period of June 1, 2010 through May 31, 2011. The resulting ARR valuation and the secured FTRs should mitigate our transmission congestion risk for that period.

ENVIRONMENTAL MATTERS

Proposed New Coal Ash Regulation:

We currently have a successful program of beneficial utilization for substantially all of our coal combustion products, including fly ash, bottom ash and gypsum, which avoids the need for disposal in specially-designed landfills. Both Wisconsin and Michigan have regulations governing the use and disposal of these materials. Recently, however, the United State Environmental Protection Agency (EPA) issued a draft rule for public comment proposing various scenarios for regulating coal combustion products including classifying coal ash as hazardous waste. If coal ash is classified as hazardous waste, it could have a material adverse effect on our ability to continue our current program. Curtailing our program could result in the loss of a revenue stream that helps to offset the cost of pollution control equipment and the activities necessary to collect the coal ash.

In addition, if coal ash is classified as hazardous waste and we terminate our coal ash utilization program, we could be required to dispose of the coal ash at a significant cost to the Company.

EPA Regulation of Greenhouse Gas Emissions under the Clean Air Act:

In December 2009, the EPA issued its endangerment finding related to greenhouse gas emissions, which set in motion a regulatory process that is leading to regulation of greenhouse gas emissions from stationary sources, including electric generating units, absent legislative or other intervention by the Administration or Congress. On March 29, 2010, the EPA finalized its determination of when the Clean Air Act's (CAA) permitting requirements for emissions from facilities, including electric generating units, would apply to greenhouse gas emissions. The regulation of stationary sources will occur in multiple steps in the coming years, with the first step scheduled to occur on January 2, 2011. The initial step covers sources that are already subject to EPA regulations for pollutants other than greenhouse gas and includes our generating facilities. Several parties have filed for judicial review of some of the EPA's new greenhouse gas rules. Regulation of greenhouse gas emissions from power plants will impact our ability to do maintenance or modify our existing facilities, and permit new facilities.

Clean Air Interstate Rule:

The EPA issued the final Clean Air Interstate Rule (CAIR) in March 2005 to facilitate the states in meeting the 8-hour ozone and Fine Particulate Matter ($PM_{2.5}$) standards by addressing the regional transport of Sulfur Dioxide (SO_2) and Nitrogen Oxide (NO_x). In 2008, the U.S. Court of Appeals for the D.C. Circuit invalidated several aspects of CAIR and remanded the rule to the EPA to promulgate a replacement rule.

In July 2010, the EPA proposed a Transport Rule to replace CAIR. The proposed Transport Rule, like CAIR, would establish individual state caps for the emissions of SO_2 and NO_X from electric generating units in the Eastern half of the United States, including Michigan and Wisconsin. The CAIR is in effect as of 2009 for NO_x and 2010 for SO_2, but

will be replaced with the new requirements of the Transport Rule, if adopted. The Transport Rule will require new reductions in 2012 for NO_x and SO_2 and additional reductions in 2014 for SO_2 for some states, including Wisconsin and Michigan. According to the EPA, the Transport Rule and other actions by States is expected to result in a 71% reduction of SO_2 and 52% reduction of NO_x emissions from power plants in the eastern United States by 2014 from 2005 emission levels.

Comments on the proposed rule are due in late September and the EPA intends to finalize the rule in mid-2011.

We previously determined that compliance with the NO_x and SO_2 emission reductions requirements under the Consent Decree entered into between the EPA and Wisconsin Electric in April 2003 would substantially mitigate costs to comply with CAIR and would achieve the levels necessary under at least the first phase of CAIR. Although the proposed limits under the Transport Rule appear to be more stringent, our previous determination remains valid.

See Factors Affecting Results, Liquidity and Capital Resources -- Environmental Matters in Item 7 of our 2009 Annual Report on Form 10-K for additional information regarding environmental matters affecting our operations.

NUCLEAR OPERATIONS

Used Nuclear Fuel and Storage Disposal:

The Nuclear Waste Policy Act established the Nuclear Waste Fund which is composed of payments made by the generators and owners of nuclear plants. Wisconsin Electric owned Point Beach through September 2007 and placed approximately $215.2 million into this fund. Effective January 31, 1998, the United States Department of Energy (DOE) failed to meet its contractual obligation to begin removing used fuel from Point Beach. Wisconsin Electric filed a complaint in November 2000 against the DOE in the Court of Federal Claims for failure to begin performance. In December 2009, the Court ruled in favor of Wisconsin Electric, granting us more than $50 million in damages. In February 2010, the DOE filed an appeal. We anticipate that any recoveries will be included in future rate cases.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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 2009 Annual Report on Form 10-K.

ITEM 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures:

Our management, with the participation of our Chief Executive Officer and Chief 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 Securities Exchange Act of 1934, as amended (the Exchange Act)) as of the end of the period covered by this report. Based upon such evaluation, our Chief Executive Officer and Chief 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 Chief Executive Officer and Chief 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 2009 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 adverse effect on our financial statements.

Cash Balance Pension Plan:

On June 30, 2009, a lawsuit was filed by Alan, M. Downes, a former employee, against the Wisconsin Energy Corporation Retirement Account Plan (Plan) in the U.S. District Court for the Eastern District of Wisconsin. Counsel representing the plaintiff is attempting to seek class certification for other similarly situated plaintiffs. The complaint alleges that Plan participants who received a lump sum distribution under the Plan prior to their normal retirement age did not receive the full benefit to which they were entitled in violation of the Employee Retirement Income Security Act of 1974 (ERISA) and are owed additional benefits, because the Plan failed to apply the correct interest crediting rate to project the cash balance account to their normal retirement age. The plaintiff has not specified the amount of relief he is seeking. An adverse outcome of this lawsuit could affect the Plan funding and expense. Although we are currently unable to predict the final outcome or impact of this litigation, we are aware that courts in similar lawsuits filed in Wisconsin have found that the interest crediting rates applied by the pension plans involved in those cases were not in compliance with ERISA.

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.

ITEM 1A. RISK FACTORS

See Item 1A. Risk Factors in our 2009 Annual Report on Form 10-K for a discussion of certain risk factors applicable to us.

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-month period ended June 30, 2010.

ISSUER PURCHASES OF EQUITY SECURITIES

2010	Total Number of Shares Purchased (a)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (Millions of Dollars)
April 1 - April 30	2,120	$51.13	-	$ -
May 1 - May 31	451	$50.02	-	$ -
June 1 - June 30	-	-	-	$ -
Total	2,571	$50.93	-	$ -

(a) All shares reported during the quarter were surrendered by employees to satisfy tax withholding obligations upon vesting of restricted stock.

ITEM 6. EXHIBITS

Exhibit No.

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

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)

/s/STEPHEN P. DICKSON

Date: July 30, 2010

Stephen P. Dickson, Vice President and Controller, Principal Accounting Officer and duly authorized officer