

**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, 2011**

<u>Commission File Number</u>	<u>Registrant; State of Incorporation Address; and Telephone Number</u>	<u>IRS Employer Identification No.</u>
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001-09057	WISCONSIN ENERGY CORPORATION (A Wisconsin Corporation) 231 West Michigan Street P.O. Box 1331 Milwaukee, WI 53201 (414) 221-2345	39-1391525
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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 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 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 <input checked="" type="checkbox"/>	Accelerated filer <input type="checkbox"/>
Non-accelerated filer <input type="checkbox"/>	Smaller reporting company <input type="checkbox"/>

(Do not check if a 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

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date (June 30, 2011):

Common Stock, \$.01 Par Value,	233,739,777 shares outstanding.
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WISCONSIN ENERGY CORPORATION

FORM 10-Q REPORT FOR THE QUARTER ENDED JUNE 30, 2011

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DEFINITION OF ABBREVIATIONS AND INDUSTRY TERMS

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

Primary Subsidiaries

We Power	W.E. Power, LLC
Wisconsin Electric	Wisconsin Electric Power Company
Wisconsin Gas	Wisconsin Gas LLC

Significant Assets

OC 1	Oak Creek expansion Unit 1
OC 2	Oak Creek expansion Unit 2
PWGS 1	Port Washington Generating Station Unit 1
PWGS 2	Port Washington Generating Station Unit 2

Other Subsidiaries and Affiliates

ATC	American Transmission Company LLC
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
WDNR	Wisconsin Department of Natural Resources

Environmental Terms

BTA	Best Technology Available
CAMR	Clean Air Mercury Rule
CSAPR	Cross-State Air Pollution Rule
MACT	Maximum Achievable Control Technology

Other Terms and Abbreviations

AQCS	Air Quality Control System
ARRs	Auction Revenue Rights
Compensation Committee	Compensation Committee of the Board of Directors
Edison Sault	Edison Sault Electric Company
ERISA	Employee Retirement Income Security Act of 1974
Exchange Act	Securities Exchange Act of 1934, as amended
Fitch	Fitch Ratings
FTRs	Financial Transmission Rights
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.
OSIP	Wisconsin Energy Corporation 1993 Omnibus Stock Incentive Plan, as amended and restated

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:

OTC	Over-the-Counter
Plan	The Wisconsin Energy Corporation Retirement Account Plan
Point Beach	Point Beach Nuclear Power Plant
PTF	<i>Power the Future</i>
S&P	Standard & Poor's Ratings Services
WPL	Wisconsin Power and Light Company, a subsidiary of Alliant Energy Corp.

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 (Exchange Act). These statements are based upon management's current expectations and are subject to risks and uncertainties that could cause our actual results to differ materially from those contemplated in the statements. Readers are cautioned not to place undue reliance on these forward-looking statements. Forward-looking statements include, among other things, statements concerning management's expectations and projections regarding earnings, completion of construction projects, regulatory matters, on-going legal proceedings, fuel costs, sources of electric energy supply, coal and gas deliveries, remediation costs, environmental and other capital expenditures, liquidity and capital resources and other matters. In some cases, forward-looking statements may be identified by reference to a future period or periods or by the use of forward-looking terminology such as "anticipates," "believes," "estimates," "expects," "forecasts," "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 catastrophic weather-related or terrorism-related damage; cyber-security threats; 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 demand for electricity and natural gas, including weather and other natural phenomena; the economic climate in our service territories; customer growth and declines; customer business conditions, including demand for their products and services; and energy conservation efforts.
- Timing, resolution and impact of pending and future rate cases and negotiations, including recovery of all costs associated with our *Power the Future* (PTF) strategy, as well as costs associated with environmental compliance, renewable generation, transmission service, distribution system upgrades, fuel and the Midwest Independent Transmission System Operator, Inc. (MISO) Energy Markets.
- Increased competition in our electric and gas markets and continued industry consolidation.
- The ability to control costs and avoid construction delays during the development and construction of new environmental controls and renewable generation.
- The impact of recent and future federal, state and local legislative and regulatory changes, including any changes in rate-setting policies or procedures; electric and gas industry restructuring initiatives; transmission or distribution system operation and/or administration initiatives; any required changes in facilities or operations to reduce the risks or impacts of potential terrorist activities; required approvals for new construction, and the siting approval process for new generation and transmission facilities and new pipeline construction; changes to the Federal Power Act and related regulations under the Energy Policy Act 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.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION -- (CONT'D)

- Current and future litigation, regulatory investigations, proceedings or inquiries, including the pending lawsuit against the Wisconsin Energy Corporation Retirement Account Plan (Plan), FERC matters, and IRS audits and other tax matters.
- Events in the global credit markets that may affect the availability and cost of capital.
- Other factors affecting our ability to access the capital markets, including general capital market conditions; our capitalization structure; market perceptions of the utility industry, us or any of our subsidiaries; and our credit ratings.
- The investment performance of our pension and other post-retirement benefit trusts.
- The financial performance of American Transmission Company LLC (ATC) and its corresponding contribution to our earnings.
- The impact of the Dodd-Frank Wall Street Reform and Consumer Protection Act and any regulations promulgated thereunder.
- The impact of the Patient Protection and Affordable Care Act and the Health Care and Education Reconciliation Act of 2010 and any related regulations.
- The effect of accounting pronouncements issued periodically by standard setting bodies, including any changes in regulatory accounting policies and practices and any requirement for U.S. registrants to follow International Financial Reporting Standards 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, 2010.

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."

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 2010 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 2010 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	
	2011	2010	2011	2010
	(Millions of Dollars, Except Per Share Amounts)			
Operating Revenues	\$ 991.7	\$ 890.9	\$ 2,320.4	\$ 2,139.5
Operating Expenses				
Fuel and purchased power	286.0	258.4	553.6	535.8
Cost of gas sold	121.8	95.8	464.2	451.6
Other operation and maintenance	298.9	317.5	612.4	652.9
Depreciation and amortization	82.3	76.8	163.6	151.2
Property and revenue taxes	28.3	26.3	56.6	52.9
Total Operating Expenses	817.3	774.8	1,850.4	1,844.4
Amortization of Gain	—	47.2	—	96.6
Operating Income	174.4	163.3	470.0	391.7
Equity in Earnings of Transmission Affiliate	15.2	15.1	30.7	30.3
Other Income, net	14.4	9.7	26.9	15.9
Interest Expense, net	57.4	53.0	120.8	102.4
Income from Continuing Operations Before Income Taxes	146.6	135.1	406.8	335.5
Income Taxes	48.6	47.6	137.9	119.0
Income from Continuing Operations	98.0	87.5	268.9	216.5
Income from Discontinued Operations, Net of Tax	11.5	1.2	11.5	1.9
Net Income	\$ 109.5	\$ 88.7	\$ 280.4	\$ 218.4
Earnings Per Share (Basic)				
Continuing operations	\$ 0.42	\$ 0.37	\$ 1.15	\$ 0.93
Discontinued operations	0.05	0.01	0.05	—
Total Earnings Per Share (Basic)	\$ 0.47	\$ 0.38	\$ 1.20	\$ 0.93
Earnings Per Share (Diluted)				
Continuing operations	\$ 0.41	\$ 0.37	\$ 1.14	\$ 0.91
Discontinued operations	0.05	—	0.05	0.01
Total Earnings Per Share (Diluted)	\$ 0.46	\$ 0.37	\$ 1.19	\$ 0.92
Weighted Average Common Shares Outstanding (Millions)				
Basic	233.7	233.8	233.7	233.8
Diluted	236.6	236.6	236.6	236.7
Dividends Per Share of Common Stock	\$ 0.26	\$ 0.20	\$ 0.52	\$ 0.40

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, 2011	December 31, 2010
	(Millions of Dollars)	
<u>Assets</u>		
Property, Plant and Equipment		
In service	\$ 12,413.4	\$ 11,590.8
Accumulated depreciation	(3,687.0)	(3,624.0)
	8,726.4	7,966.8
Construction work in progress	1,032.9	1,569.9
Leased facilities, net	62.0	64.8
Net Property, Plant and Equipment	9,821.3	9,601.5
Investments		
Equity investment in transmission affiliate	341.1	330.5
Other	35.6	45.8
Total Investments	376.7	376.3
Current Assets		
Cash and cash equivalents	10.6	24.5
Restricted cash	45.5	8.3
Accounts receivable	344.9	344.6
Accrued revenues	172.4	280.3
Materials, supplies and inventories	339.1	379.1
Regulatory assets	53.0	54.4
Prepayments and other	206.4	239.9
Total Current Assets	1,171.9	1,331.1
Deferred Charges and Other Assets		
Regulatory assets	1,055.0	1,090.1
Goodwill	441.9	441.9
Other	209.5	218.9
Total Deferred Charges and Other Assets	1,706.4	1,750.9
Total Assets	\$ 13,076.3	\$ 13,059.8
<u>Capitalization and Liabilities</u>		
Capitalization		
Common equity	\$ 3,947.6	\$ 3,802.1
Preferred stock of subsidiary	30.4	30.4
Long-term debt	4,334.6	3,932.0
Total Capitalization	8,312.6	7,764.5
Current Liabilities		
Long-term debt due currently	30.6	473.4
Short-term debt	542.4	657.9
Accounts payable	309.8	315.4
Regulatory liabilities	15.3	15.3
Other	245.6	259.1
Total Current Liabilities	1,143.7	1,721.1
Deferred Credits and Other Liabilities		
Regulatory liabilities	931.5	883.8
Deferred income taxes - long-term	1,339.8	1,154.8
Deferred revenue, net	781.3	805.5
Pension and other benefit obligations	233.5	353.2
Other	333.9	376.9
Total Deferred Credits and Other Liabilities	3,620.0	3,574.2
Total Capitalization and Liabilities	\$ 13,076.3	\$ 13,059.8

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	
	2011	2010
	(Millions of Dollars)	
Operating Activities		
Net income	\$ 280.4	\$ 218.4
Reconciliation to cash		
Depreciation and amortization	169.2	157.4
Amortization of gain	—	(96.6)
Equity in earnings of transmission affiliate	(30.7)	(30.3)
Distributions from transmission affiliate	24.6	24.8
Deferred income taxes and investment tax credits, net	137.0	7.3
Deferred revenue	2.8	55.0
Contributions to qualified benefit plans	(122.4)	—
Change in - Accounts receivable and accrued revenues	91.1	72.5
Inventories	40.0	(12.1)
Other current assets	10.2	20.4
Accounts payable	(38.7)	(29.8)
Accrued income taxes, net	59.2	(13.3)
Deferred costs, net	13.0	13.0
Other current liabilities	11.4	14.7
Other, net	1.5	22.3
Cash Provided by Operating Activities	648.6	423.7
Investing Activities		
Capital expenditures	(347.1)	(379.1)
Investment in transmission affiliate	(4.6)	(3.9)
Proceeds from asset sales	38.5	63.5
Change in restricted cash	(37.2)	81.8
Other, net	(17.1)	(37.6)
Cash Used in Investing Activities	(367.5)	(275.3)
Financing Activities		
Exercise of stock options	29.6	43.2
Purchase of common stock	(51.6)	(68.9)
Dividends paid on common stock	(121.5)	(93.5)
Issuance of long-term debt	420.0	530.0
Retirement and repurchase of long-term debt	(456.9)	(263.5)
Change in short-term debt	(115.5)	(304.7)
Other, net	0.9	(0.7)
Cash Used in Financing Activities	(295.0)	(158.1)
Change in Cash and Cash Equivalents	(13.9)	(9.7)
Cash and Cash Equivalents at Beginning of Period	24.5	20.2
Cash and Cash Equivalents at End of Period	\$ 10.6	\$ 10.5

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 2010 Annual Report on Form 10-K. In the opinion of management, we have included all adjustments, normal and recurring in nature, necessary for a fair presentation of the results of operations, cash flows and financial position in the accompanying income statements, statements of cash flows and balance sheets. The results of operations for the three and six months ended June 30, 2011 are not necessarily indicative of the results which may be expected for the entire fiscal year 2011 because of seasonal and other factors.

Reclassifications: On January 20, 2011, our Board of Directors approved a two-for-one stock split of our common stock, which was effected through a stock dividend. New shares were distributed on March 1, 2011 to stockholders of record at the close of business on February 14, 2011. All share and per share information has been restated for all periods presented to reflect this stock split.

2 -- NEW ACCOUNTING PRONOUNCEMENTS

No new accounting pronouncements were issued or adopted during the first six months of 2011 which would have a material impact on our financial condition, results of operations or cash flows.

3 -- ACCOUNTING AND REPORTING FOR POWER THE FUTURE GENERATING UNITS

Background: As part of our PTF strategy, our non-utility subsidiary, We Power, built four new generating units, Port Washington Generating Station Unit 1 (PWGS 1), Port Washington Generating Station Unit 2 (PWGS 2), Oak Creek expansion Unit 1 (OC 1) and Oak Creek expansion Unit 2 (OC 2), which are 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, OC 1 and OC 2 were placed in service in July 2005, May 2008, February 2010 and January 2011, respectively. The accompanying consolidated condensed 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 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 in service in November 2007 and January 2009, respectively.

During Construction: Under the terms of each lease, we collected 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 was approximately 14%. The carrying costs that we collected in rates were recorded as deferred revenue and are amortized to revenue over the term of each lease. During the construction of our PTF units, we capitalized interest costs at an overall weighted-average pre-tax cost of interest, which was approximately 5% for the six months ended June 30, 2010. Capitalized interest is included in the total cost of the PTF units.

Plant in Service: Now that the PTF units are placed in service, we expect to continue 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 were established by the PSCW. The authorized cash costs exclude capitalized interest since carrying costs were 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 under each lease was established at rates determined in accordance with the terms of each lease.

We recognize revenues (consisting of the lease payments included in rates and the amortization of the deferred revenue) on a levelized basis over the term of the lease. We depreciate the PTF assets 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 I -- Common Equity in our 2010 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 other than necessary adjustments as a result of our stock split. 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	
	2011	2010	2011	2010
	(Millions of Dollars)			
Stock options	\$ 0.7	\$ 1.9	\$ 1.3	\$ 3.8
Performance units	3.4	7.9	4.4	10.6
Restricted stock	0.4	0.5	0.9	0.8
Share-based compensation expense	<u>\$ 4.5</u>	<u>\$ 10.3</u>	<u>\$ 6.6</u>	<u>\$ 15.2</u>
Related Tax Benefit	<u>\$ 1.8</u>	<u>\$ 4.1</u>	<u>\$ 2.6</u>	<u>\$ 6.1</u>

Stock Option Activity: During the first six months of 2011, the Compensation Committee granted 458,180 non-qualified stock options that had an estimated fair value of \$3.17 per share. During the first six months of 2010, the Compensation Committee granted 549,500 stock options that had an estimated fair value of \$3.36 per share. The following assumptions were used to value the options using a binomial option pricing model:

	2011	2010
Risk-free interest rate	0.2% - 3.4%	0.2% - 3.9%
Dividend yield	3.9%	3.7%
Expected volatility	19.0%	20.3%
Expected forfeiture rate	2.0%	2.0%
Expected life (years)	5.5	5.9

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

The following is a summary of our stock option activity for the three and six months ended June 30, 2011:

Stock Options	Number of Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (Millions)
Outstanding as of April 1, 2011	12,766,126	\$ 21.29		
Granted	—	\$ —		
Exercised	(840,900)	\$ 19.72		
Forfeited	—	\$ —		
Outstanding as of June 30, 2011	<u>11,925,226</u>	\$ 21.40		
Outstanding as of January 1, 2011	13,036,466	\$ 20.81		
Granted	458,180	\$ 29.35		
Exercised	(1,569,420)	\$ 18.83		
Forfeited	—	\$ —		
Outstanding as of June 30, 2011	<u>11,925,226</u>	\$ 21.40	5.7	\$ 118.6
Exercisable as of June 30, 2011	<u>8,771,716</u>	\$ 20.87	4.9	\$ 91.9

The intrinsic value of options exercised was \$9.9 million and \$19.0 million for the three and six months ended June 30, 2011, and \$13.6 million and \$25.1 million for the same periods in 2010, respectively. Cash received from options exercised was \$29.6 million and \$43.2 million for the six months ended June 30, 2011 and 2010, respectively. The actual tax benefit realized for the tax deductions from option exercises for the same periods was approximately \$7.5 million and \$9.7 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 2011.

The following table summarizes information about stock options outstanding as of June 30, 2011:

Range of Exercise Prices	Options Outstanding			Options Exercisable		
	Number of Options	Weighted-Average Exercise Price	Remaining Contractual Life (Years)	Number of Options	Weighted-Average Exercise Price	Remaining Contractual Life (Years)
\$11.33 to \$17.10	2,602,898	\$ 15.96	2.7	2,602,898	\$ 15.96	2.7
\$19.74 to \$21.11	3,774,648	\$ 20.61	6.4	1,572,948	\$ 19.91	4.9
\$23.88 to \$29.35	5,547,680	\$ 24.49	6.6	4,595,870	\$ 23.98	6.1
	<u>11,925,226</u>	\$ 21.40	5.7	<u>8,771,716</u>	\$ 20.87	4.9

The following table summarizes information about our non-vested options during the three and six months ended June 30, 2011:

Non-Vested Stock Options	Number of Options	Weighted-Average Fair Value
Non-vested as of April 1, 2011	3,210,680	\$ 3.78
Granted	—	\$ —
Vested	(57,170)	\$ 3.78
Forfeited	—	\$ —
Non-vested as of June 30, 2011	<u>3,153,510</u>	\$ 3.78
Non-vested as of January 1, 2011	5,272,570	\$ 4.27
Granted	458,180	\$ 3.17
Vested	(2,577,240)	\$ 4.66
Forfeited	—	\$ —
Non-vested as of June 30, 2011	<u>3,153,510</u>	\$ 3.78

As of June 30, 2011, total compensation costs related to non-vested stock options not yet recognized was approximately \$1.9 million, which is expected to be recognized over the next 14 months on a weighted-average basis.

Restricted Shares: During the first six months of 2011, the Compensation Committee granted 74,850 restricted shares to certain key employees and directors. These awards have a three-year vesting period, and generally, one-third of the award vests on each anniversary of the grant date. During the vesting period, restricted share recipients 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, 2011:

Restricted Shares	Number of Shares	Weighted-Average Grant Date Fair Value
Outstanding as of April 1, 2011	207,904	
Granted	—	\$ —
Released	(8,150)	\$ 13.02
Forfeited	(934)	\$ 27.04
Outstanding as of June 30, 2011	<u>198,820</u>	
Outstanding as of January 1, 2011	205,404	
Granted	74,850	\$ 29.00
Released	(78,624)	\$ 19.03
Forfeited	(2,810)	\$ 26.45
Outstanding as of June 30, 2011	<u>198,820</u>	

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 \$0.2 million and \$2.3 million for the three and six months ended June 30, 2011, and \$0.3 million and \$1.0 million for the same periods in 2010, respectively. The actual tax benefit realized for the tax deductions from released restricted shares was \$0.1 million and \$0.7 million for the three and six months ended June 30, 2011, and \$0.1 million and \$0.2 million for the same periods in 2010, respectively.

As of June 30, 2011, total compensation cost related to restricted stock not yet recognized was approximately \$3.4 million, which is expected to be recognized over the next 25 months on a weighted-average basis.

Performance Units: In January 2011 and 2010, the Compensation Committee granted 435,690 and 555,830 performance units, respectively, to officers and other key employees under the Wisconsin Energy Performance Unit Plan. Under the grants, the ultimate number of units that will be awarded is dependent upon the achievement of certain financial performance of our stock over a three-year period. Under the terms of the award, participants may earn between 0% and 175% of the base performance unit award. All grants are settled in cash. We are accruing compensation costs over the three-year period based on our estimate of the final expected value of the awards. Performance units earned as of December 31, 2010 and 2009 vested and were settled during the first quarter of 2011 and 2010, and had a total intrinsic value of \$12.6 million and \$9.8 million, respectively. The actual tax benefit realized for the tax deductions from the settlement of performance units was approximately \$4.3 million and \$3.4 million, respectively. As of June 30, 2011, total compensation cost related to performance units not yet recognized was approximately \$22.7 million, which is expected to be recognized over the next 22 months on a weighted-average basis.

Restrictions: Wisconsin Energy's ability as a holding company to pay common dividends primarily depends on the availability of funds received from its non-utility subsidiary, We Power, and its utility subsidiaries. Various financing arrangements and regulatory requirements impose certain restrictions on the ability of our subsidiaries to transfer funds to us in the form of cash dividends, loans or advances. In addition, under Wisconsin law, Wisconsin Electric and Wisconsin Gas are prohibited from loaning funds, either directly or indirectly, to Wisconsin Energy. See Note I -- Common Equity in our 2010 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, 2011 and 2010 was \$280.6 million and \$218.6 million, respectively, which approximates net income for each of those periods.

Share Repurchase Program: On May 5, 2011, Wisconsin Energy's Board of Directors authorized a share repurchase program for up to \$300 million of our common stock through the end of 2013. Funds for the repurchases are expected to come from internally generated funds and working capital supplemented, if required in the short-term, by the sale of commercial paper. The repurchase program does not obligate Wisconsin Energy to acquire any specific number of shares and may be suspended or terminated by the Board of Directors at any time. Through June 30, 2011, we did not repurchase any shares pursuant to this program.

5 -- DISCONTINUED OPERATIONS AND DIVESTITURES

The following table summarizes the net impacts of the discontinued operations on our earnings for the three and six months ended June 30:

	Three Months Ended June 30		Six Months Ended June 30	
	2011	2010	2011	2010
	(Millions of Dollars)			
Income from Continuing Operations	\$ 98.0	\$ 87.5	\$ 268.9	\$ 216.5
Income from Discontinued Edison Sault operations, net of tax	—	1.0	—	1.8
Income from Discontinued other operations, net of tax (a)	11.5	0.2	11.5	0.1
Net Income	<u>\$ 109.5</u>	<u>\$ 88.7</u>	<u>\$ 280.4</u>	<u>\$ 218.4</u>

- (a) During 2011, we reached a favorable resolution of uncertain state and federal tax positions associated with our previously discontinued manufacturing business.

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

Edison Sault: Effective May 4, 2010, we sold Edison Sault to Cloverland Electric Cooperative for approximately \$63.0 million. We retained Edison Sault's ownership interest in ATC.

6 -- LONG TERM DEBT

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

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

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 hierarchical 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, 2011			
	Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Assets:				
Restricted Cash	\$ 45.5	\$ —	\$ —	\$ 45.5
Derivatives	3.9	6.9	14.6	25.4
Total	\$ 49.4	\$ 6.9	\$ 14.6	\$ 70.9
Liabilities:				
Derivatives	\$ 2.8	\$ 0.1	\$ —	\$ 2.9
Total	\$ 2.8	\$ 0.1	\$ —	\$ 2.9

Recurring Fair Value Measures	As of December 31, 2010			
	Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Assets:				
Restricted Cash	\$ 8.3	\$ —	\$ —	\$ 8.3
Derivatives	4.5	5.3	5.9	15.7
Total	\$ 12.8	\$ 5.3	\$ 5.9	\$ 24.0
Liabilities:				
Derivatives	\$ 6.1	\$ 5.5	\$ —	\$ 11.6
Total	\$ 6.1	\$ 5.5	\$ —	\$ 11.6

Restricted cash consists of certificates of deposit and government backed interest bearing securities and represents (i) for 2010, the remaining funds to be distributed to customers resulting from the net proceeds received from the sale of the Point Beach Nuclear Power Plant (Point Beach), and (ii) for 2011, the settlement we received from the United States Department of Energy (DOE) during the first quarter of 2011, which will be returned, net of costs incurred, to customers in future rate cases. Derivatives reflect positions we hold in exchange-traded derivative contracts and OTC derivative contracts. Exchange-traded derivative contracts, which include futures and exchange-traded options, are generally based on unadjusted quoted prices in active markets and are classified within Level 1. Some OTC derivative contracts are valued using broker or dealer quotations, or market transactions in either the listed or OTC markets utilizing a mid-market pricing convention (the mid-point between bid and ask prices), as appropriate. In such cases, these derivatives are classified within Level 2. Certain OTC derivatives may utilize models to measure fair value. Generally, we use a similar model to value similar instruments. Valuation models utilize various inputs which include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, other observable inputs for the asset or liability, and market-corroborated inputs (i.e., inputs derived principally from or corroborated by observable market data by correlation or other means). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. Certain OTC derivatives are in less active markets with a lower availability of pricing information which might not be observable in or corroborated by the market. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized in Level 3.

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

	Quarter to Date		Year to Date	
	2011	2010	2011	2010
	(Millions of Dollars)			
Beginning Balance	\$ 2.1	\$ 1.9	\$ 5.9	\$ 5.8
Realized and unrealized gains (losses)	—	—	—	—
Purchases, issuances and settlements	12.5	14.0	8.7	10.1
Transfers in and/or out of Level 3	—	—	—	—
Balance as of June 30	<u>\$ 14.6</u>	<u>\$ 15.9</u>	<u>\$ 14.6</u>	<u>\$ 15.9</u>
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:

Financial Instruments	June 30, 2011		December 31, 2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(Millions of Dollars)			
Preferred stock, no redemption required	\$ 30.4	\$ 21.9	\$ 30.4	\$ 23.5
Long-term debt, including current portion	\$ 4,251.2	\$ 4,516.5	\$ 4,288.0	\$ 4,578.0

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, 2011, we recognized \$10.9 million in regulatory assets and \$27.3 million in regulatory liabilities related to derivatives in comparison to \$22.0 million in regulatory assets and \$15.3 million in regulatory liabilities as of December 31, 2010.

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 \$0.1 million is recorded in Other deferred charges and other assets, and the long-term portion of our derivative liabilities of \$0.1 million is recorded in Other deferred credits and other liabilities as of June 30, 2011. Our Consolidated Condensed Balance Sheets as of June 30, 2011 and December 31, 2010 include:

	June 30, 2011		December 31, 2010	
	Derivative Asset	Derivative Liability	Derivative Asset	Derivative Liability
	(Millions of Dollars)			
Natural Gas	\$ 4.5	\$ 2.9	\$ 2.5	\$ 11.6
Fuel Oil	3.9	—	4.4	—
FTRs	14.6	—	5.9	—
Coal	2.4	—	2.9	—
Total	<u>\$ 25.4</u>	<u>\$ 2.9</u>	<u>\$ 15.7</u>	<u>\$ 11.6</u>

Our Consolidated Condensed Income Statements include gains (losses) on derivative instruments used in our risk management strategies under Fuel and purchased power for those commodities supporting our electric operations and under Cost of gas sold for the natural gas sold to our customers. Our estimated notional volumes and gains (losses) for the three and six months ended June 30, 2011 and 2010 were as follows:

	Three Months Ended June 30, 2011		Three Months Ended June 30, 2010	
	Volume	Gains (Losses)	Volume	Gains (Losses)
	(Millions of Dollars)		(Millions of Dollars)	
Natural Gas	18.9 million Dth	\$ (6.6)	19.3 million Dth	\$ (9.1)
Power	zero MWh	—	102,400 MWh	(0.2)
Fuel Oil	3.4 million gallons	2.1	2.0 million gallons	—
FTRs	6,191 MW	1.5	6,657 MW	3.2
Total		<u>\$ (3.0)</u>		<u>\$ (6.1)</u>

	Six Months Ended June 30, 2011		Six Months Ended June 30, 2010	
	Volume	Gains (Losses)	Volume	Gains (Losses)
	(Millions of Dollars)		(Millions of Dollars)	
Natural Gas	38.3 million Dth	\$ (17.2)	47.6 million Dth	\$ (20.7)
Power	zero MWh	—	159,600 MWh	—
Fuel Oil	6.6 million gallons	2.5	3.8 million gallons	—
FTRs	12,543 MW	5.3	12,088 MW	12.2
Total		<u>\$ (9.4)</u>		<u>\$ (8.5)</u>

As of June 30, 2011 and December 31, 2010, we posted collateral of \$5.9 million and \$11.7 million, respectively, in our margin accounts. These amounts are recorded on the balance sheets 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 were as follows:

Benefit Plan Cost Components	Pension Costs			
	Three Months Ended June 30		Six Months Ended June 30	
	2011	2010	2011	2010
	(Millions of Dollars)			
Net Periodic Benefit Cost				
Service cost	\$ 3.3	\$ 4.9	\$ 7.9	\$ 11.8
Interest cost	17.1	16.4	33.8	33.8
Expected return on plan assets	(20.4)	(19.0)	(41.1)	(38.7)
Amortization of:				
Prior service cost	0.5	0.5	1.1	1.1
Actuarial loss	9.0	6.7	17.1	13.3
Net Periodic Benefit Cost	<u>\$ 9.5</u>	<u>\$ 9.5</u>	<u>\$ 18.8</u>	<u>\$ 21.3</u>

Benefit Plan Cost Components	OPEB Costs			
	Three Months Ended June 30		Six Months Ended June 30	
	2011	2010	2011	2010
	(Millions of Dollars)			
Net Periodic Benefit Cost				
Service cost	\$ 2.4	\$ 2.8	\$ 5.2	\$ 5.6
Interest cost	5.1	5.1	10.4	10.5
Expected return on plan assets	(4.1)	(3.6)	(8.4)	(7.2)
Amortization of:				
Transition obligation	0.1	0.1	0.2	0.2
Prior service (credit)	(0.5)	(2.9)	(1.0)	(5.9)
Actuarial loss	1.5	2.7	3.0	5.4
Net Periodic Benefit Cost	<u>\$ 4.5</u>	<u>\$ 4.2</u>	<u>\$ 9.4</u>	<u>\$ 8.6</u>

In January 2011, we contributed \$122.4 million to our qualified benefit plans. Future contributions to the plans will be dependent upon many factors, including the performance of existing plan assets and long-term discount rates.

Postemployment Benefits: Postemployment benefits provided to former or inactive employees are recognized when an event occurs. The estimated liability for such benefits was \$13.9 million as of June 30, 2011 and \$14.8 million as of December 31, 2010.

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, 2011, we had the following guarantees:

	Maximum Potential		
	Future Payments	Outstanding	Liability Recorded
	(Millions of Dollars)		
Guarantees	\$ 2.8	\$ 0.1	\$ —
Letters of Credit	\$ 1.6	\$ 0.7	\$ —

We provide guarantees to support obligations of our affiliates to third parties under 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.

11 -- SEGMENT INFORMATION

Summarized financial information concerning our operating segments for the three and six months ended June 30, 2011 and 2010 is shown in the following table:

Three Months Ended	Operating Segments		Corporate & Other (a) & Reconciling Items	Total Consolidated
	Energy			
	Utility	Non-Utility		
(Millions of Dollars)				
<u>June 30, 2011</u>				
Operating Revenues (b)	\$ 977.9	\$ 111.3	\$ (97.5)	\$ 991.7
Depreciation and Amortization	\$ 63.9	\$ 18.3	\$ 0.1	\$ 82.3
Operating Income (Loss)	\$ 88.1	\$ 87.9	\$ (1.6)	\$ 174.4
Equity in Earnings (Loss) of Unconsolidated Affiliates	\$ 15.2	\$ —	\$ (0.1)	\$ 15.1
Interest Expense, Net	\$ 27.2	\$ 17.0	\$ 13.2	\$ 57.4
Income Tax Expense (Benefit)	\$ 29.1	\$ 28.1	\$ (8.6)	\$ 48.6
Income from Discontinued Operations, Net of Tax	\$ —	\$ —	\$ 11.5	\$ 11.5
Net Income	\$ 61.1	\$ 42.8	\$ 5.6	\$ 109.5
Capital Expenditures	\$ 203.8	\$ 6.7	\$ 1.1	\$ 211.6
<u>June 30, 2010</u>				
Operating Revenues (b)	\$ 880.5	\$ 86.4	\$ (76.0)	\$ 890.9
Depreciation and Amortization	\$ 62.7	\$ 13.8	\$ 0.3	\$ 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

Six Months Ended	Operating Segments		Corporate & Other (a) & Reconciling Items	Total Consolidated
	Utility	Non-Utility		
(Millions of Dollars)				
<u>June 30, 2011</u>				
Operating Revenues (b)	\$ 2,294.4	\$ 214.5	\$ (188.5)	\$ 2,320.4
Depreciation and Amortization	\$ 127.3	\$ 36.0	\$ 0.3	\$ 163.6
Operating Income (Loss)	\$ 301.1	\$ 171.9	\$ (3.0)	\$ 470.0
Equity in Earnings (Loss) of Unconsolidated Affiliates	\$ 30.7	\$ —	\$ (0.2)	\$ 30.5
Interest Expense, Net	\$ 55.3	\$ 32.9	\$ 32.6	\$ 120.8
Income Tax Expense (Benefit)	\$ 100.4	\$ 55.8	\$ (18.3)	\$ 137.9
Income from Discontinued Operations, Net of Tax	\$ —	\$ —	\$ 11.5	\$ 11.5
Net Income (Loss)	\$ 202.1	\$ 83.3	\$ (5.0)	\$ 280.4
Capital Expenditures	\$ 331.0	\$ 14.9	\$ 1.2	\$ 347.1
Total Assets (c)	\$ 12,765.1	\$ 2,969.3	\$ (2,658.1)	\$ 13,076.3
<u>June 30, 2010</u>				
Operating Revenues (b)	\$ 2,123.4	\$ 152.0	\$ (135.9)	\$ 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

- (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 \$97.7 million and \$76.2 million for the three months ended June 30, 2011 and 2010, respectively, and \$188.9 million and \$136.2 million for the six months ended June 30, 2011 and 2010, respectively, is included in Operating Revenues. This elimination is primarily between We Power and Wisconsin Electric.
- (c) An elimination of \$2,414.9 million and \$1,820.8 million is included in Total Assets as of June 30, 2011 and 2010, 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 that 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 two 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 11 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 \$337.7 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, 2011 and 2010 were \$32.1 million and \$31.0 million, respectively. 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.

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

Manufactured Gas Plant Sites: We have identified several sites at which Wisconsin Electric, Wisconsin Gas, or a predecessor company historically owned or operated a manufactured gas plant. These sites have been substantially remediated or are at various stages of investigation, monitoring and remediation. We have also identified other sites that may have been impacted by historical manufactured gas plant activities. Based upon ongoing analysis, we estimate that the future costs for detailed site investigation and future remediation costs may range from \$35 million to \$65 million over the next ten years. This estimate is dependent upon several variables including, among other things, the extent of remediation, changes in technology and changes in regulation. As of June 30, 2011, we have established reserves of \$45.1 million related to future remediation costs.

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

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 also provided customary indemnifications to WPL in connection with the sale of our interest in Edgewater Generating Unit 5. We have established reserves as deemed appropriate for these indemnification provisions.

Cash Balance Pension Plan: In June 2009, a lawsuit was filed by Alan M. Downes, a former employee, against the Plan in the U.S. District Court for the Eastern District of Wisconsin. Counsel representing the plaintiff has sought 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. In September 2010, the plaintiff filed a First Amended Class Action Complaint alleging additional claims under ERISA and adding Wisconsin Energy as a defendant. The plaintiff has not specified the amount of relief he is seeking.

In March 2011, after the matter was addressed by the Plan's Employee Benefits Committee and following the Committee's review and analysis of the facts and evolving state of the law, the Plan acknowledged in an amended answer that it had used an incorrect interest crediting rate in computing lump sum payments prior to normal retirement age. The Committee determined the interest crediting rates that should be applied to address the interest crediting rate calculation and determined that the benefits for certain eligible participants should be recalculated. The plaintiff is opposing the Committee's actions and the Court has not yet decided what deference, if any, to give to the Committee's decision. Therefore, we are currently unable to predict the final outcome or impact of this litigation. An adverse outcome of this lawsuit could have a material adverse effect on Plan funding and expense and our results of operations.

Income Taxes: During the second quarter of 2011, our state and federal unrecognized tax benefits decreased by approximately \$15.9 million exclusive of accrued interest, of which \$10.2 million relates to discontinued operations. This decrease was the result of the expiration of state statute of limitations, as well as effective settlements with state and federal taxing authorities. Additionally, within the next 12 months, it is reasonably possible that our unrecognized tax benefits associated with discontinued operations may decrease by approximately \$1.6 million due to the expiration of state statute of limitations.

14 -- SUPPLEMENTAL CASH FLOW INFORMATION

During the six months ended June 30, 2011, we paid \$125.1 million in interest, net of amounts capitalized, and received \$49.4 million in net refunds from income taxes. 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.

As of June 30, 2011 and 2010, the amount of accounts payable related to capital expenditures was \$51.2 million and \$24.4 million, respectively.

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

RESULTS OF OPERATIONS -- THREE MONTHS ENDED JUNE 30, 2011

CONSOLIDATED EARNINGS

The following table compares our operating income by business segment and our net income during the second quarter of 2011 with the second quarter of 2010, including favorable (better (B)) or unfavorable (worse (W)) variances:

	Three Months Ended June 30		
	2011	B (W)	2010
	(Millions of Dollars)		
Utility Energy Segment	\$ 88.1	\$ (9.7)	\$ 97.8
Non-Utility Energy Segment	87.9	21.0	66.9
Corporate and Other	(1.6)	(0.2)	(1.4)
Total Operating Income	174.4	11.1	163.3
Equity in Earnings of Transmission Affiliate	15.2	0.1	15.1
Other Income, net	14.4	4.7	9.7
Interest Expense, net	57.4	(4.4)	53.0
Income from Continuing Operations Before Income Taxes	146.6	11.5	135.1
Income Taxes	48.6	(1.0)	47.6
Income from Continuing Operations	\$ 98.0	\$ 10.5	\$ 87.5
Diluted Earnings Per Share from Continuing Operations	\$ 0.41	\$ 0.04	\$ 0.37
Diluted Earnings Per Share from Discontinued Operations	\$ 0.05	\$ 0.05	\$ —

UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

Our utility energy segment contributed \$88.1 million of operating income during the second quarter of 2011, a decrease of \$9.7 million, or 9.9%, compared with the second quarter of 2010. The following table summarizes the operating income of this segment between the comparative quarters:

Utility Energy Segment	Three Months Ended June 30		
	2011	B (W)	2010
	(Millions of Dollars)		
Operating Revenues			
Electric	\$ 762.6	\$ 60.9	\$ 701.7
Gas	207.8	35.7	172.1
Other	7.5	0.8	6.7
Total Operating Revenues	977.9	97.4	880.5
Fuel and Purchased Power	287.2	(27.6)	259.6
Cost of Gas Sold	121.8	(26.0)	95.8
Gross Margin	568.9	43.8	525.1
Other Operating Expenses			
Other Operation and Maintenance	388.8	(3.1)	385.7
Depreciation and Amortization	63.9	(1.2)	62.7
Property and Revenue Taxes	28.1	(2.0)	26.1
Total Operating Expenses	889.8	(59.9)	829.9
Amortization of Gain	—	(47.2)	47.2
Operating Income	\$ 88.1	\$ (9.7)	\$ 97.8

Electric Utility Revenues and Sales

The following table compares electric utility operating revenues and MWh sales by customer class during the second quarter of 2011 with the second quarter of 2010:

Electric Utility Operations	Three Months Ended June 30					
	Electric Revenues			MWh Sales		
	2011	B (W)	2010	2011	B (W)	2010
	(Millions of Dollars)			(Thousands)		
Customer Class						
Residential	\$ 259.8	\$ 8.4	\$ 251.4	1,835.6	(38.3)	1,873.9
Small Commercial/Industrial	240.7	10.3	230.4	2,065.2	(81.1)	2,146.3
Large Commercial/Industrial	193.4	22.1	171.3	2,502.1	43.5	2,458.6
Other - Retail	5.2	0.2	5.0	34.9	(0.9)	35.8
Total Retail	699.1	41.0	658.1	6,437.8	(76.8)	6,514.6
Wholesale - Other	39.9	9.8	30.1	526.1	126.1	400.0
Resale - Utilities	15.2	7.1	8.1	437.6	126.9	310.7
Other Operating Revenues	8.4	3.0	5.4	—	—	—
Total	<u>\$ 762.6</u>	<u>\$ 60.9</u>	<u>\$ 701.7</u>	<u>7,401.5</u>	<u>176.2</u>	<u>7,225.3</u>
Weather -- Degree Days (a)						
Heating (936 Normal)				1,037	366	671
Cooling (171 Normal)				113	(95)	208

(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 \$60.9 million, or 8.7%, when compared to the second quarter of 2010. The most significant factors that caused a change in revenues were:

- 2011 increase of approximately \$47.2 million, reflecting the reduction of Point Beach bill credits to retail customers.
- Net pricing increases totaling \$10.2 million, which includes rates to recover the increase in 2011 fuel costs that became effective April 29, 2011. For additional information, see Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters.
- Unfavorable weather that decreased electric revenues by an estimated \$22.5 million as compared to the second quarter of 2010.

As measured by cooling degree days, the second quarter of 2011 was 45.7% cooler than the same period in 2010 and 33.9% cooler than normal. Collectively, retail sales to our residential and small commercial and industrial customers, who are more weather sensitive, decreased by 3.0%. Electric sales to our largest customers, two iron ore mines, increased significantly for the quarter. If these sales are excluded, sales to our large commercial and industrial customers decreased slightly for the second quarter of 2011 as compared to the second quarter of 2010.

Fuel and Purchased Power

Our fuel and purchased power costs increased by \$27.6 million, or 10.6%, when compared to the second quarter of 2010. This increase was primarily caused by a 2.4% increase in total MWh sales, increased coal and transportation costs, and changes in the mix of MWh generation caused by plant outages that resulted in increased costs as compared to the second quarter of 2010.

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 2011 with the second quarter of 2010. We believe gross margin is a better performance indicator than revenues because changes in the cost of gas sold flow through to revenue under gas cost recovery mechanisms. Between the comparative periods, total gas operating revenues increased by \$35.7 million, or 20.7%, primarily because of

cooler weather in the second quarter of 2011.

	Three Months Ended June 30		
	2011	B (W)	2010
	(Millions of Dollars)		
Gas Operating Revenues	\$ 207.8	\$ 35.7	\$ 172.1
Cost of Gas Sold	121.8	(26.0)	95.8
Gross Margin	<u>\$ 86.0</u>	<u>\$ 9.7</u>	<u>\$ 76.3</u>

The following table compares gas utility gross margin and natural gas therm deliveries by customer class during the second quarter of 2011 with the second quarter of 2010:

Gas Utility Operations	Three Months Ended June 30					
	Gross Margin			Therm Deliveries		
	2011	B (W)	2010	2011	B (W)	2010
	(Millions of Dollars)			(Millions)		
Customer Class						
Residential	\$ 54.2	\$ 6.0	\$ 48.2	116.7	25.6	91.1
Commercial/Industrial	17.3	3.5	13.8	72.5	20.7	51.8
Interruptible	0.5	—	0.5	3.1	(0.8)	3.9
Total Retail	<u>72.0</u>	<u>9.5</u>	<u>62.5</u>	<u>192.3</u>	<u>45.5</u>	<u>146.8</u>
Transported Gas	12.2	1.1	11.1	203.4	13.3	190.1
Other	1.8	(0.9)	2.7	—	—	—
Total	<u>\$ 86.0</u>	<u>\$ 9.7</u>	<u>\$ 76.3</u>	<u>395.7</u>	<u>58.8</u>	<u>336.9</u>
Weather -- Degree Days (a)						
Heating (936 Normal)				1,037	366	671

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

Our gas margin increased by \$9.7 million, or 12.7%, when compared to the second quarter of 2010. This increase primarily relates to an increase in sales volumes as a result of cooler weather during the second quarter of 2011 that increased heating loads. As measured by heating degree days, the second quarter of 2011 was 54.5% cooler than the same period in 2010 and 10.8% cooler than normal.

Other Operation and Maintenance Expense

Our other operation and maintenance expense increased by \$3.1 million, or approximately 0.8%, when compared to the second quarter of 2010.

Depreciation and Amortization Expense

Our depreciation and amortization expense increased by \$1.2 million, or approximately 1.9%, when compared to the second quarter of 2010, primarily because of an overall increase in utility plant in service.

Amortization of Gain

In connection with the September 2007 sale of Point Beach, we reached an agreement with our regulators to allow for the net gain on the sale to be used for the benefit of our customers. The majority of the benefits were returned to customers in the form of bill credits. The net gain was originally recorded as a regulatory liability, and it was amortized to the income statement as we issued bill credits to customers. When the bill credits were issued to customers, we transferred cash from the restricted accounts to the unrestricted accounts, adjusted for taxes. All bill credits associated with the sale of Point Beach were applied to customers as of December 31, 2010, and as a result, the Amortization of Gain was zero during the second quarter of 2011 as compared to \$47.2 million during the second quarter of 2010.

NON-UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

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

The table below reflects a full quarter's earnings in 2011 and 2010 for PWGS 1, PWGS 2, OC 1 and the common facilities for the Oak Creek expansion. It also reflects a full quarter's earnings in 2011 for OC 2. 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.

	Three Months Ended June 30, 2011			
	(Millions of Dollars)			
	Port Washington	Oak Creek Expansion	All Other	Total
Operating Revenues	\$ 26.5	\$ 82.2	\$ 2.6	\$ 111.3
Operation and Maintenance Expense	0.5	3.1 (a)	1.5	5.1
Depreciation Expense	5.0	12.9	0.4	18.3
Operating Income	<u>\$ 21.0</u>	<u>\$ 66.2</u>	<u>\$ 0.7</u>	<u>\$ 87.9</u>

	Three Months 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 (a)	2.5	5.7
Depreciation Expense	4.9	8.5	0.4	13.8
Operating Income	<u>\$ 21.1</u>	<u>\$ 44.8</u>	<u>\$ 1.0</u>	<u>\$ 66.9</u>

(a) Includes \$2.8 million and \$2.7 million for the three months ended June 30, 2011 and 2010, respectively, of costs that are billed to Wisconsin Electric under the lease agreements.

CONSOLIDATED OTHER INCOME, NET

Other income, net increased by approximately \$4.7 million, or 48.5%, when compared to the second quarter of 2010. This increase primarily relates to increased AFUDC - Equity related to the construction of the Oak Creek AQCS project and the Glacier Hills Wind Park.

CONSOLIDATED INTEREST EXPENSE, NET

Interest Expense	Three Months Ended June 30		
	2011	B (W)	2010
	(Millions of Dollars)		
Gross Interest Costs	\$ 63.1	\$ 2.0	\$ 65.1
Less: Capitalized Interest	5.7	(6.4)	12.1
Interest Expense, net	<u>\$ 57.4</u>	<u>\$ (4.4)</u>	<u>\$ 53.0</u>

Our gross interest costs decreased by \$2.0 million, or 3.1%, during the second quarter of 2011, primarily because of a reduction in our long-term debt weighted-average interest rate and lower long-term debt balances compared to

the same period in 2010. In April 2011, we used cash and commercial paper to retire \$450 million of long-term debt that matured. Our capitalized interest decreased by \$6.4 million primarily because we stopped capitalizing interest on OC 2 when it was placed in service in January 2011. As a result, our net interest expense increased by \$4.4 million, or 8.3%, as compared to the second quarter of 2010.

CONSOLIDATED INCOME TAXES

For the second quarter of 2011, our effective tax rate applicable to continuing operations was 33.2% compared to 35.2% for the second quarter of 2010. During the second quarter of 2011, our tax expense was reduced by \$2.2 million primarily due to the favorable resolution of uncertain tax positions. For additional information, see Note H -- Income Taxes in our 2010 Annual Report on Form 10-K.

DISCONTINUED OPERATIONS

During 2011, we reached a favorable resolution of uncertain state and federal tax positions associated with our previously discontinued manufacturing business.

RESULTS OF OPERATIONS -- SIX MONTHS ENDED JUNE 30, 2011

CONSOLIDATED EARNINGS

The following table compares our operating income by business segment and our net income during the first six months of 2011 with the first six months of 2010, including favorable (better (B)) or unfavorable (worse (W)) variances:

	Six Months Ended June 30		
	2011	B (W)	2010
		(Millions of Dollars)	
Utility Energy Segment	\$ 301.1	\$ 25.2	\$ 275.9
Non-Utility Energy Segment	171.9	52.9	119.0
Corporate and Other	(3.0)	0.2	(3.2)
Total Operating Income	470.0	78.3	391.7
Equity in Earnings of Transmission Affiliate	30.7	0.4	30.3
Other Income, net	26.9	11.0	15.9
Interest Expense, net	120.8	(18.4)	102.4
Income from Continuing Operations Before Income Taxes	406.8	71.3	335.5
Income Taxes	137.9	(18.9)	119.0
Income from Continuing Operations	\$ 268.9	\$ 52.4	\$ 216.5
Diluted Earnings Per Share from Continuing Operations	\$ 1.14	\$ 0.23	\$ 0.91
Diluted Earnings Per Share from Discontinued Operations	\$ 0.05	\$ 0.04	\$ 0.01

UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

Our utility energy segment contributed \$301.1 million of operating income during the first six months of 2011, an increase of \$25.2 million, or 9.1%, compared with the first six months of 2010. The following table summarizes the operating income of this segment between the comparative periods:

Utility Energy Segment	Six Months Ended June 30		
	2011	B (W)	2010
	(Millions of Dollars)		
Operating Revenues			
Electric	\$ 1,539.2	\$ 133.7	\$ 1,405.5
Gas	732.5	36.2	696.3
Other	22.7	1.1	21.6
Total Operating Revenues	2,294.4	171.0	2,123.4
Fuel and Purchased Power	556.0	(17.8)	538.2
Cost of Gas Sold	464.2	(12.6)	451.6
Gross Margin	1,274.2	140.6	1,133.6
Other Operating Expenses			
Other Operation and Maintenance	789.7	(13.1)	776.6
Depreciation and Amortization	127.3	(2.1)	125.2
Property and Revenue Taxes	56.1	(3.6)	52.5
Total Operating Expenses	1,993.3	(49.2)	1,944.1
Amortization of Gain	—	(96.6)	96.6
Operating Income	\$ 301.1	\$ 25.2	\$ 275.9

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 2011 with the first six months of 2010:

Electric Utility Operations	Six Months Ended June 30					
	Electric Revenues			MWh Sales		
	2011	B (W)	2010	2011	B (W)	2010
	(Millions of Dollars)			(Thousands)		
Customer Class						
Residential	\$ 542.8	\$ 30.0	\$ 512.8	3,865.6	(9.6)	3,875.2
Small Commercial/Industrial	487.1	39.6	447.5	4,263.9	(30.1)	4,294.0
Large Commercial/Industrial	372.0	45.6	326.4	4,875.8	52.9	4,822.9
Other - Retail	11.3	0.5	10.8	74.9	(1.3)	76.2
Total Retail	1,413.2	115.7	1,297.5	13,080.2	11.9	13,068.3
Wholesale - Other	75.9	4.4	71.5	1,004.9	(31.4)	1,036.3
Resale - Utilities	32.7	9.3	23.4	1,006.2	329.6	676.6
Other Operating Revenues	17.4	4.3	13.1	—	—	—
Total	\$ 1,539.2	\$ 133.7	\$ 1,405.5	15,091.3	310.1	14,781.2
Weather -- Degree Days (a)						
Heating (4,194 Normal)				4,481	666	3,815
Cooling (172 Normal)				113	(95)	208

(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 \$133.7 million, or 9.5%, when compared to the first six months of 2010. The most significant factors that caused a change in revenues were:

- 2011 increase of approximately \$96.6 million, reflecting the reduction of Point Beach bill credits to retail customers.
- Net pricing increases totaling \$28.2 million, which includes rates related to our 2010 fuel recovery request that became effective March 25, 2010, and our request to review 2011 fuel costs that became effective April 29, 2011. For information on these rate orders, see Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters.
- Unfavorable weather during the second quarter that decreased electric revenues by an estimated \$9.3 million

as compared to the first six months of 2010.

Electric sales to our largest customers, two iron ore mines, increased significantly for the first six months of 2011. If these sales are excluded, sales to our large commercial and industrial customers decreased slightly for the first six months of 2011 as compared to the first six months of 2010.

Fuel and Purchased Power

Our fuel and purchased power costs increased by \$17.8 million, or 3.3%, when compared to the first six months of 2010. This increase was primarily caused by a 2.1% increase in total MWh sales, increased coal and transportation costs, and changes in the mix of MWh generation caused by plant outages that resulted in increased costs as compared to the first six months of 2010, partially offset by lower natural gas prices.

Gas Utility Revenues, Gross Margin and Therm Deliveries

A comparison follows of gas utility operating revenues, gross margin and gas deliveries during the first six months of 2011 with the first six months of 2010. We believe gross margin is a better performance indicator than revenues because changes in the cost of gas sold flow through to revenue under gas cost recovery mechanisms. Between the comparative periods, total gas operating revenues increased by \$36.2 million, or 5.2%, primarily because of colder weather during the first six months of 2011.

	Six Months Ended June 30		
	2011	B (W)	2010
	(Millions of Dollars)		
Gas Operating Revenues	\$ 732.5	\$ 36.2	\$ 696.3
Cost of Gas Sold	464.2	(12.6)	451.6
Gross Margin	<u>\$ 268.3</u>	<u>\$ 23.6</u>	<u>\$ 244.7</u>

The following table compares gas utility gross margin and natural gas therm deliveries by customer class during the first six months of 2011 with the first six months of 2010:

Gas Utility Operations	Six Months Ended June 30					
	Gross Margin			Therm Deliveries		
	2011	B (W)	2010	2011	B (W)	2010
	(Millions of Dollars)			(Millions)		
Customer Class						
Residential	\$ 172.8	\$ 15.6	\$ 157.2	507.7	67.8	439.9
Commercial/Industrial	62.5	7.9	54.6	293.9	43.1	250.8
Interruptible	1.1	(0.1)	1.2	9.5	(1.9)	11.4
Total Retail	<u>236.4</u>	<u>23.4</u>	<u>213.0</u>	<u>811.1</u>	<u>109.0</u>	<u>702.1</u>
Transported Gas	27.8	1.3	26.5	467.1	(7.4)	474.5
Other	4.1	(1.1)	5.2	—	—	—
Total	<u>\$ 268.3</u>	<u>\$ 23.6</u>	<u>\$ 244.7</u>	<u>1,278.2</u>	<u>101.6</u>	<u>1,176.6</u>
Weather -- Degree Days (a)						
Heating (4,194 Normal)				4,481	666	3,815

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

Our gas margin increased by \$23.6 million, or 9.6%, when compared to the first six months of 2010. We estimate that approximately \$22.5 million of this increase relates to an increase in sales volumes as a result of colder weather during the first six months of 2011 that increased heating loads. As measured by heating degree days, the first six months of 2011 were 17.5% colder than the same period in 2010 and 6.8% colder than normal.

Other Operation and Maintenance Expense

Our other operation and maintenance expense increased by \$13.1 million, or approximately 1.7%, when compared to the first six months of 2010. Operation and maintenance expenses at our power plants increased approximately \$5.9 million primarily because of higher maintenance costs at our power plants as a result of the timing of outages and increased costs related to our Oak Creek AQCS project. In addition, expenses related to our electric distribution system increased by approximately \$3.3 million.

Depreciation and Amortization Expense

Our depreciation and amortization expense increased by \$2.1 million, or approximately 1.7%, when compared to the first six months of 2010, primarily because of an overall increase in utility plant in service.

Amortization of Gain

The Amortization of Gain was zero during the first six months of 2011 as compared to \$96.6 million during the first six months of 2010. For additional information, see Amortization of Gain under Results of Operations -- Three Months Ended June 30, 2011.

NON-UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

The table below reflects six months of earnings in 2011 and 2010 for PWGS 1, PWGS 2 and the common facilities for the Oak Creek expansion. It also reflects five months of earnings in 2010 and six months of earnings in 2011 for OC 1, and five and a half months of earnings in 2011 for OC 2. 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, 2011			
	(Millions of Dollars)			
	Port Washington	Oak Creek Expansion	All Other	Total
Operating Revenues	\$ 52.5	\$ 159.4	\$ 2.6	\$ 214.5
Operation and Maintenance Expense	0.6	3.7 (a)	2.3	6.6
Depreciation Expense	9.9	25.2	0.9	36.0
Operating Income (Loss)	\$ 42.0	\$ 130.5	\$ (0.6)	\$ 171.9

	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 (a)	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

(a) Includes \$3.1 million and \$3.4 million for the six months ended June 30, 2011 and 2010, respectively, of costs that are billed to Wisconsin Electric under the lease agreements.

CONSOLIDATED OTHER INCOME, NET

Other income, net increased by approximately \$11.0 million, or 69.2%, when compared to the first six months of 2010. This increase primarily relates to increased AFUDC - Equity related to the construction of the Oak Creek

AQCS project and the Glacier Hills Wind Park.

CONSOLIDATED INTEREST EXPENSE, NET

Interest Expense	Six Months Ended June 30		
	2011	B (W)	2010
		(Millions of Dollars)	
Gross Interest Costs	\$ 133.0	\$ (4.8)	\$ 128.2
Less: Capitalized Interest	12.2	(13.6)	25.8
Interest Expense, net	<u>\$ 120.8</u>	<u>\$ (18.4)</u>	<u>\$ 102.4</u>

Our gross interest costs increased by \$4.8 million, or 3.7%, during the first six months of 2011, primarily because of higher long-term debt balances compared to the same period in 2010. In January 2011, we issued \$420 million of long-term debt and used the net proceeds to repay short-term debt incurred to finance the construction of OC 2 and for other corporate purposes. Partially offsetting this increase, in April 2011, we used cash and commercial paper to retire \$450 million of long-term debt that matured. Our capitalized interest decreased by \$13.6 million primarily because we stopped capitalizing interest on OC 2 when it was placed in service in January 2011. As a result, our net interest expense increased by \$18.4 million, or 18.0%, as compared to the first six months of 2010.

CONSOLIDATED INCOME TAXES

For the first six months of 2011, our effective tax rate applicable to continuing operations was 33.9% compared to 35.5% for the first six months of 2010. During the first six months of 2011, our tax expense was reduced by \$2.2 million primarily due to the favorable resolution of uncertain tax positions. For additional information, see Note H -- Income Taxes in our 2010 Annual Report on Form 10-K. We expect our 2011 annual effective tax rate to be between 34% and 35%.

DISCONTINUED OPERATIONS

During 2011, we reached a favorable resolution of uncertain state and federal tax positions associated with our previously discontinued manufacturing business.

LIQUIDITY AND CAPITAL RESOURCES

CASH FLOWS

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

Wisconsin Energy Corporation	2011	2010
	(Millions of Dollars)	
Cash Provided by (Used in)		
Operating Activities	\$ 648.6	\$ 423.7
Investing Activities	\$ (367.5)	\$ (275.3)
Financing Activities	\$ (295.0)	\$ (158.1)

Operating Activities

Cash provided by operating activities was \$648.6 million during the six months ended June 30, 2011 as compared to \$423.7 million during the six months ended June 30, 2010. The largest increases in cash provided by operating activities related to higher net income, higher depreciation expense, higher deferred income tax benefits and the elimination of the amortization of the gain on the sale of Point Beach. Combined these items totaled \$586.6 million during the first six months of 2011 as compared to \$286.5 million during the first six months of 2010. We expect this trend to continue during 2011. The largest reduction in cash provided by operating activities related to our contributions to qualified benefit plans. During the first six months of 2011, we contributed \$122.4 million to our

qualified benefit plans. We made no contributions to our qualified plans during the first six months of 2010.

Investing Activities

Cash used in investing activities was \$367.5 million during the six months ended June 30, 2011, which was \$92.2 million higher than the same period in 2010. This increase in cash used reflects changes in restricted cash, partially offset by decreased capital expenditures. During the first six months of 2011, our restricted cash increased primarily because of the nuclear fuel settlement we received from the DOE. During the same period in 2010, there was a decrease due to the release of restricted cash related to the Point Beach bill credits. See Nuclear Operations in this report for additional information regarding the settlement with the DOE. In addition, capital expenditures decreased by approximately \$32.0 million during the first six months of 2011 as compared to the first six months of 2010 as a result of the completion of construction of OC 1 in February 2010 and OC 2 in January 2011.

Financing Activities

Cash used in financing activities was \$295.0 million during the six months ended June 30, 2011, which was \$136.9 million higher than the same period in 2010. During the first six months of 2011, we decreased our total debt by \$152.4 million compared to a decrease of \$38.2 million in our total debt during the first six months of 2010. In addition, we paid \$28.0 million more in cash dividends during the first six months of 2011 as compared to the first six months of 2010. In January 2011, our Board of Directors approved a 30.0% increase in the quarterly common stock dividend for 2011.

CAPITAL RESOURCES AND REQUIREMENTS

Liquidity

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

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

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

As of June 30, 2011, we had approximately \$1.2 billion of available, undrawn lines under our bank back-up credit facilities, and approximately \$542.4 million of commercial paper outstanding on a consolidated basis that was supported by the available lines of credit. During the first six months of 2011, our maximum commercial paper outstanding was \$717.3 million with a weighted-average interest rate of 0.24%.

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, 2011:

Company	Total Facility	Letters of Credit (Millions of Dollars)	Credit Available	Facility Expiration
Wisconsin Energy	\$ 450.0	\$ 0.4	\$ 449.6	December 2013
Wisconsin Electric	\$ 500.0	\$ 5.9	\$ 494.1	December 2013
Wisconsin Gas	\$ 300.0	\$ —	\$ 300.0	December 2013

The following table shows our capitalization structure as of June 30, 2011, as well as an adjusted capitalization structure that we believe is consistent with the manner in which the rating agencies currently view Wisconsin Energy's 2007 Series A Junior Subordinated notes (Junior Notes):

Capitalization Structure	Actual	Adjusted
	(Millions of Dollars)	
Common Equity	\$ 3,947.6	\$ 4,197.6
Preferred Stock of Subsidiary	30.4	30.4
Long-Term Debt (including current maturities)	4,365.2	4,115.2
Short-Term Debt	542.4	542.4
Total Capitalization	<u>\$ 8,885.6</u>	<u>\$ 8,885.6</u>
Total Debt	\$ 4,907.6	\$ 4,657.6
Ratio of Debt to Total Capitalization	55.2%	52.4%

Included in Long-Term Debt on our Consolidated Condensed Balance Sheet as of June 30, 2011 is \$500 million aggregate principal amount of the Junior Notes. The adjusted presentation attributes \$250 million of the Junior Notes to Common Equity and \$250 million to Long-Term Debt. We believe this presentation is consistent with the 50% or greater equity credit the majority of rating agencies currently attribute to the Junior Notes.

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

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, 2011, the repurchased bonds were still outstanding, but were reported as a reduction in our consolidated long-term debt because they are held by Wisconsin Electric. Depending on market conditions and other factors, Wisconsin Electric may change the method used to determine the interest rate on the bonds and have them remarketed to third parties.

Credit Rating Risk

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

In June 2011, S&P raised the rating of Wisconsin Energy's junior unsecured debt to BBB from BBB-; affirmed the ratings of the remaining debt of Wisconsin Energy, Wisconsin Electric, Wisconsin Gas and ERGSS; and revised the ratings outlooks assigned to each company from positive to stable.

In June 2011, Fitch affirmed the ratings of Wisconsin Energy, Wisconsin Electric, Wisconsin Gas, Wisconsin Energy Capital Corporation and ERGSS, and the stable ratings outlooks assigned to each company.

Subject to other factors affecting the credit markets as a whole, we believe our current ratings should provide a significant degree of flexibility in obtaining funds on competitive terms. However, these security ratings reflect the views of the rating agencies only. An explanation of the significance of these ratings may be obtained from each rating agency. Such ratings are not a recommendation to buy, sell or hold securities. Any rating can be revised upward or downward or withdrawn at any time by a rating agency.

See Capital Resources and Requirements -- Credit Rating Risk in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations in our 2010 Annual Report on Form 10-K for additional information related to our credit rating risk.

Capital Requirements

Capital Expenditures: Capital requirements during the remainder of 2011 are expected to be principally for capital expenditures in our utility operations relating to our electric distribution system and environmental controls at our existing Oak Creek generating units. Our 2011 consolidated capital expenditure budget is approximately \$950 million.

Common Stock Matters: On May 5, 2011, Wisconsin Energy's Board of Directors authorized a share repurchase program for up to \$300 million of our common stock through the end of 2013. Funds for the repurchases are expected to come from internally generated funds and working capital supplemented, if required in the short-term, by the sale of commercial paper. The repurchase program does not obligate Wisconsin Energy to acquire any specific number of shares and may be suspended or terminated by the Board of Directors at any time. We did not repurchase any shares during the second quarter of 2011 pursuant to this program, but through July 29, 2011, we have acquired approximately 795,400 shares in open market purchases at a cost of \$24.9 million.

In addition, the Board of Directors adopted a new dividend policy for Wisconsin Energy starting in 2012. Pursuant to this new policy, we will target a dividend payout ratio that trends to 60% of earnings over the period from 2012 to 2015.

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 \$21.0 billion as of June 30, 2011 compared with \$21.1 billion as of December 31, 2010. Our total contractual obligations and other commercial commitments as of June 30, 2011 decreased slightly compared with December 31, 2010 primarily due to long-term debt retired at its maturity in April 2011, partially offset by long-term debt issued in January 2011 in connection with the commercial operation of OC 2.

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 2010 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

OC 2 was placed into service on January 12, 2011. All of the PTF units are now in service and are positioned to provide a significant portion of our future generation needs. We are recovering our costs in these units through lease payments associated with PWGS 1, PWGS 2 and OC 1 that are billed from We Power to Wisconsin Electric and then recovered in Wisconsin Electric's rates as authorized by the PSCW, the Michigan Public Service Commission (MPSC) and FERC. Wisconsin Electric is recovering the lease payments associated with OC 2 as authorized by the PSCW and FERC, and has requested authorization from the MPSC in the rate case filed in July 2011. See Factors Affecting Results, Liquidity and Capital Resources -- Power the Future in Item 7 of our 2010 Annual Report on Form 10-K for additional information on PTF.

UTILITY RATES AND REGULATORY MATTERS

2012 Wisconsin Rate Case: On May 26, 2011, Wisconsin Electric and Wisconsin Gas filed an application with the PSCW to initiate rate proceedings. In lieu of a traditional rate proceeding, we have requested an alternative approach, which if approved by the PSCW, would result in no increase in 2012 base rates for our customers. In 2012, Wisconsin Electric and Wisconsin Gas would seek base rate increases to be effective in 2013. In order for us to proceed under this alternative approach, Wisconsin Electric and Wisconsin Gas requested that the PSCW issue an order that:

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

The application states that if we receive an order from the PSCW that addresses only a portion of these issues, or that includes additional conditions, we would instead proceed with a traditional rate case. If we found it necessary to proceed with a traditional rate case, we expect Wisconsin Electric's rate request would include increases of approximately 6.0% for its electric customers, 0.9% for its natural gas customers, 10.2% for its Valley steam utility customers and 6.9% for its Milwaukee County steam utility customers. We expect Wisconsin Gas would request a 0.2% rate increase for its natural gas customers. We expect a decision from the PSCW on our proposal in August 2011.

2012 Michigan Rate Case: On July 5, 2011, Wisconsin Electric filed a \$17.5 million rate increase request with the MPSC, primarily to recover the costs of environmental upgrades and OC 2. Michigan law allows utilities, upon the satisfaction of certain conditions, to self-implement a rate increase request, subject to refund with interest. Therefore, we expect to self-implement \$7.7 million of the rate increase request effective in January 2012. A final decision from the MPSC is expected in July 2012.

2010 Wisconsin Rate Case: As part of its final decision in the 2010 rate case, the PSCW authorized Wisconsin Electric to reopen the docket in 2010 to review updated 2011 fuel costs. On September 3, 2010, Wisconsin Electric filed an application with the PSCW to reopen the docket to review updated 2011 fuel costs and to set rates for 2011 that reflect those costs. Wisconsin Electric requested an increase in 2011 Wisconsin retail electric rates of \$38.4 million, or 1.4%, related to the increase in 2011 monitored fuel costs as compared to the level of monitored fuel costs then embedded in rates. In December 2010, Wisconsin Electric reduced its request by approximately \$5.2 million. Adjustments by the PSCW reduced the request by an additional \$7.8 million. The PSCW issued its final decision, which increased annual Wisconsin retail rates by \$25.4 million effective April 29, 2011. The net increase is being driven primarily by an increase in the delivered cost of coal.

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

2009 Fuel Order: Wisconsin Electric operates under a fuel cost adjustment clause for fuel and purchased power costs associated with the generation of electricity for its retail customers in Wisconsin. Under the fuel rules in effect in 2008 and 2009, a Wisconsin utility could request an emergency rate increase if projected costs fell outside of a prescribed range of costs which was plus or minus 2% of the fuel rate approved in a general rate proceeding.

In March 2008, Wisconsin Electric filed a request for an emergency rate increase with the PSCW to recover forecasted increases in fuel and purchased power costs. The PSCW authorized a total increase of \$118.9 million. In April 2009, Wisconsin Electric filed a request with the PSCW to decrease annual Wisconsin retail electric rates by

\$67.2 million because it forecasted that its monitored fuel cost for 2009 would fall outside the range prescribed by the PSCW and would be less than the fuel cost reflected in then authorized rates. The PSCW approved this request on an interim basis with rates effective May 1, 2009.

The PSCW staff audited the fuel costs for the year 2009 to determine whether Wisconsin Electric collected excess revenues as a result of the fuel surcharges that were in place in 2008 and 2009. Under the fuel rules, if a utility collects excess revenues in a year in which it implemented an emergency fuel surcharge, it is required to refund to customers the over-collected fuel surcharge revenue up to the amount of the excess revenues. In February 2011, the PSCW closed out its review of this matter and determined that Wisconsin Electric did not collect any excess revenues.

Wisconsin Fuel Rules: Embedded within Wisconsin Electric's base rates is an amount to recover fuel costs. In April 2010, the Wisconsin legislature passed the Fuel Rule Bill, and the Governor signed it in May 2010. This bill instructed the PSCW to defer, for subsequent rate recovery or refund, any under-collection or over-collection of fuel costs that are outside of the utility's symmetrical fuel cost tolerance, which the PSCW set at plus or minus 2% of the utility's approved fuel cost plan. In August 2010, the PSCW proposed new fuel rules pursuant to this legislation, which the Wisconsin legislature reviewed and sent back to the PSCW for additional rule-making. In December 2010, the PSCW revised the proposed rules as requested by the legislature and sent the revised rules back to the legislature for review. The new fuel rules are now in effect and fuel cost plans approved by the PSCW after January 1, 2011 will be subject to the new rules.

Renewable Energy Portfolio: 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 the federal production tax credit. In March 2010, we filed a request for a Certificate of Authority for the project with the PSCW. At its April 28, 2011 open meeting, the PSCW expressed concern about the overall cost of the project for our electric customers and directed Wisconsin Electric and Domtar to propose a lower cost structure for electric customers. Wisconsin Electric and Domtar submitted a joint response on May 3, 2011. On May 12, 2011, the PSCW issued its final decision approving the project and construction commenced on June 27, 2011. We currently expect to invest between \$245 million and \$255 million, excluding AFUDC, in the plant and for it to be completed during the fall of 2013.

We have received all of the permits necessary to construct the biomass facility. In April 2011, opponents of the project filed a request for a contested case hearing related to the air pollution control construction permit issued by the WDNR. The WDNR denied the request in May 2011 because it was improperly filed. In June 2011, the opponents filed a petition for judicial review with the Marathon County Circuit Court seeking review of the WDNR's decision to deny the request for a contested case hearing. On July 8, 2011, we filed a request to intervene in the judicial proceeding.

Edgewater Generating Unit 5: On March 1, 2011, we sold our 25% interest in Edgewater Generating Unit 5 to WPL for our net book value, including working capital, of approximately \$38 million.

See Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters in Item 7 of our 2010 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 Price (LMP) system that has been implemented in certain northeastern and mid-Atlantic states. The LMP system includes the ability to mitigate or eliminate congestion costs through Auction Revenue Rights (ARRs) and FTRs. ARRs are allocated to market participants by MISO and FTRs are purchased through auctions. A new allocation and auction was completed for the period of June 1, 2011 through May 31, 2012. The resulting ARR valuation and the secured FTRs should mitigate our transmission congestion risk for that period.

ENVIRONMENTAL MATTERS

Mercury and Other Hazardous Air Pollutants: The United States Environmental Protection Agency (EPA) issued the final Clean Air Mercury Rule (CAMR) in March 2005, addressing mercury emissions from new and existing coal-fired power plants. The federal rule was challenged by a number of states including Wisconsin and Michigan. In February 2008, the U.S. Court of Appeals for the D.C. Circuit vacated CAMR and sent the rule back to the EPA for reconsideration.

In December 2008, a number of environmental groups filed a complaint with the D.C. Circuit asking that the court place the EPA on a schedule for promulgating Maximum Achievable Control Technology (MACT) limits for fossil-fuel fired electric generating units to address hazardous air pollutants, including mercury. In October 2009, the EPA published notice of a proposed consent decree in connection with this litigation that would place the EPA on a schedule to set a MACT rule for coal and oil-fired electric generating units in 2011. In April 2010, the D.C. District Court approved a settlement agreement between the EPA and the plaintiffs in the litigation setting a firm schedule for the remanded rule-making. In accordance with this settlement, the EPA issued a proposed rule on March 16, 2011, and is required to issue the final rule by November 16, 2011. The proposed MACT rule is intended to reduce emissions of numerous hazardous air pollutants, including mercury. We are evaluating the potential impact of the proposed rule on the operation of our existing coal-fired generation facilities. Based upon our review, the Milwaukee County, Valley and Presque Isle power plants may require additional modifications. In addition, we believe that our clean air strategy, including the environmental upgrades that have already been constructed and that are currently under construction at our other plants, positions those plants well to meet the proposed requirements.

Cross-State Air Pollution Rule: On July 6, 2011, the EPA signed a final rule, the Cross-State Air Pollution Rule (CSAPR), formerly known as the Clean Air Transport Rule. This rule had been proposed in 2010 to replace the Clean Air Interstate Rule, which had been invalidated and remanded to the EPA in 2008.

The stated purpose of the CSAPR is to limit the interstate transport of emissions of nitrogen oxides and sulfur dioxide that contribute to fine particulate matter and ozone in downwind states. While the rule does not yet have a published effective date, compliance is required in 2012. Although we believe the previous installation of controls on our generation fleet will help us to meet the requirements of CSAPR, we are still evaluating this rule and are currently unable to determine its impact on our operations, if any.

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

The EPA has been in the process of revising the Phase II rules since mid-2007. In December 2010, the EPA and Riverkeeper Inc. (plaintiff in the litigation) set a firm schedule for the remanded Section 316(b) Phase II rulemaking. In accordance with the settlement agreement, the EPA proposed a new Phase II rule on March 28, 2011. The settlement requires a final rule by July 27, 2012. Once the rule is final, it will apply to all of our existing generating facilities with cooling water intake structures other than the Oak Creek expansion, which was permitted under the Phase I rules.

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

The EPA has proposed that the BTA for entrainment mortality reduction be determined on a case-by-case basis. Therefore, site-specific analysis would be required to determine BTA with respect to entrainment. The proposed rule allows permitting authorities to determine BTA controls on a site-specific basis following the consideration of several factors, including the cost of control technologies, the non-water quality impacts of control technologies, the monetary and non-monetary benefits of control technologies, land availability, and remaining useful plant life.

Because the entrainment reduction standard is a site-specific determination, we cannot yet determine what, if any, intake structure or operational modifications will be required to meet this proposed requirement.

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

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

See Factors Affecting Results, Liquidity and Capital Resources -- Environmental Matters in Item 7 of our 2010 Annual Report on Form 10-K for additional information regarding environmental matters affecting our operations.

LEGAL MATTERS

Cash Balance Pension Plan: In June 2009, a lawsuit was filed by Alan M. Downes, a former employee, against the Plan in the U.S. District Court for the Eastern District of Wisconsin. Counsel representing the plaintiff has sought 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 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. In September 2010, the plaintiff filed a First Amended Class Action Complaint alleging additional claims under ERISA and adding Wisconsin Energy as a defendant. The plaintiff has not specified the amount of relief he is seeking.

In March 2011, after the matter was addressed by the Plan's Employee Benefits Committee and following the Committee's review and analysis of the facts and evolving state of the law, the Plan acknowledged in an amended answer that it had used an incorrect interest crediting rate in computing lump sum payments prior to normal retirement age. The Committee determined the interest crediting rates that should be applied to address the interest crediting rate calculation and determined that the benefits for certain eligible participants should be recalculated. The plaintiff is opposing the Committee's actions and the Court has not yet decided what deference, if any, to give to the Committee's decision. Therefore, we are currently unable to predict the final outcome or impact of this litigation. An adverse outcome of this lawsuit could have a material adverse effect on Plan funding and expense and our results of operations.

Stray Voltage: In recent years, dairy farmers have commenced actions or made claims against Wisconsin Electric for loss of milk production and other damages to livestock allegedly caused by stray voltage and ground currents resulting from the operation of its electrical system, even though that electrical system has been operated within the parameters of the PSCW's order. The Wisconsin Supreme Court has rejected the arguments that, if a utility company's measurement of stray voltage is below the PSCW "level of concern," that utility could not be found negligent in stray voltage cases. Additionally, the Court has held that the PSCW regulations regarding stray voltage were only minimum standards to be considered by a jury in stray voltage litigation. As a result of these rulings, claims by dairy farmers for livestock damage have been based upon ground currents with levels measuring less than the PSCW "level of concern." In December 2008, a stray voltage lawsuit was filed against Wisconsin Electric. This lawsuit was settled in May 2011. This settlement did not have a material adverse effect on our financial condition or results of operations. Another stray voltage lawsuit was filed against Wisconsin Electric on January 27, 2011. We do not believe this lawsuit has merit and we will vigorously defend it. This lawsuit is not expected to have a material adverse effect on our financial statements. We continue to evaluate various options and strategies to mitigate this risk.

NUCLEAR OPERATIONS

Used Nuclear Fuel Storage and 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 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. During the fourth quarter of 2010, we negotiated a settlement with the DOE for \$45.5 million, which we received in the first quarter of 2011. We anticipate that this amount, net of costs incurred, will be returned to customers in future rate cases.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

There have been no material changes related to market risk from the disclosures presented in our Annual Report on Form 10-K for the year ended December 31, 2010. 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 2010 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 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 2010 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, we believe, after consultation with legal counsel, that the ultimate resolution of these proceedings will not have a material adverse effect on our financial statements.

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.

OTHER MATTERS

See Factors Affecting Results, Liquidity and Capital Resources -- Legal Matters in Item 2 of this report for information regarding a lawsuit filed against the Plan, as well as information concerning stray voltage litigation. The lawsuit involving the Plan was previously reported in Part II -- Other Information in our Form 10-Q for the quarter ended March 31, 2011.

ITEM 1A. RISK FACTORS

There have been no material changes from the risk factors presented in our Annual Report on Form 10-K for the year ended December 31, 2010. See Item 1A. Risk Factors in our 2010 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 months ended June 30, 2011:

ISSUER PURCHASES OF EQUITY SECURITIES

2011	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	4,272	\$ 29.57	—	\$ —
May 1 - May 31	—	\$ —	—	\$ —
June 1 - June 30	—	\$ —	—	\$ —
Total	<u>4,272</u>	<u>\$ 29.57</u>	<u>—</u>	<u>\$ —</u>

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

ITEM 5. OTHER INFORMATION

The Compensation Committee previously approved, subject to stockholder approval, amendments to the Wisconsin Energy Corporation 1993 Omnibus Stock Incentive Plan, as amended and restated (OSIP), that would, among other things, (i) increase the number of shares of Wisconsin Energy common stock reserved for issuance under the OSIP by an additional 33,000,000 shares; (ii) establish a multiplier to count share usage for full share awards granted under the OSIP, such as restricted stock, of 4.23 shares for every share of Wisconsin Energy common stock issued under the OSIP; (iii) extend the expiration date of the OSIP to ten years after the 2011 annual meeting of stockholders (May 5, 2021); (iv) add restricted stock units and dividend equivalents as forms of awards; and (v) expand the performance criteria for "performance-based awards" to help ensure that such awards comply with Section 162(m) of the U.S. Internal Revenue Code, and establish Wisconsin Energy's authority to grant such awards under the OSIP through the 2016 annual meeting of stockholders. Wisconsin Energy's stockholders approved the amendments to the OSIP at their 2011 annual meeting.

In addition to the 33,000,000 shares reserved for issuance under the OSIP, there are 1,319,272 shares remaining from the shares previously authorized for issuance by Wisconsin Energy's stockholders.

The following summary of the other terms of the OSIP is not complete and is subject to, and qualified in its entirety by reference to, the full text of the OSIP which is attached as Exhibit 10.1 and incorporated herein by reference.

The OSIP provides for administration by a committee, to be comprised of either the Compensation Committee or another committee designated by the Board consisting of non-employee directors. The Compensation Committee currently administers the OSIP. Among the committee's powers are the authority to interpret the OSIP, select participants and determine the form, amount and other terms and conditions of awards.

Directors, officers and other key employees of Wisconsin Energy or any of its subsidiaries are eligible to participate in the OSIP. In addition to restricted stock units and dividend equivalents, the other types of awards that may be granted under the OSIP include stock, stock options, restricted stock, stock appreciation rights and performance units. All awards will be settled in stock or cash as determined by the committee.

In the event of a "change in control" as defined in the OSIP, all outstanding options and stock appreciation rights will become immediately exercisable and all other awards will immediately vest with all performance goals immediately achieved.

The Board of Directors may terminate or amend the OSIP at any time, provided, however, without stockholder approval, the Board may not reduce the exercise price of outstanding stock options or stock appreciation rights or cancel outstanding options or stock appreciation rights in exchange for cash, other awards or options or stock appreciation rights having a lower exercise price.

ITEM 6. EXHIBITS

Exhibit No.

10 Material Contracts

- 10.1 Wisconsin Energy Corporation Omnibus Stock Incentive Plan, Amended and Restated Effective as of May 5, 2011.

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)

Date: August 2, 2011 /s/STEPHEN P. DICKSON
Stephen P. Dickson, Vice President and Controller, Principal
Accounting Officer and duly authorized officer