

**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 **March 31, 2009**

<u>Commission File Number</u>	<u>Registrant; State of Incorporation Address; and Telephone Number</u>	<u>IRS Employer Identification No.</u>
001-01245	WISCONSIN ELECTRIC POWER COMPANY (A Wisconsin Corporation) 231 West Michigan Street P.O. Box 2046 Milwaukee, WI 53201 (414) 221-2345	39-0476280

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 type="checkbox"/>	Accelerated filer <input type="checkbox"/>
Non-accelerated filer <input checked="" type="checkbox"/> (Do not check if a smaller reporting company)	Smaller reporting company <input type="checkbox"/>

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 (March 31, 2009):

Common Stock, \$10 Par Value,	33,289,327 shares outstanding.
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All of the common stock of Wisconsin Electric Power Company is owned by Wisconsin Energy Corporation.

WISCONSIN ELECTRIC POWER COMPANY

FORM 10-Q REPORT FOR THE QUARTER ENDED MARCH 31, 2009

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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:

Wisconsin Electric Subsidiary and Affiliates

Primary Subsidiary and Affiliates

Bostco	Bostco LLC
Edison Sault	Edison Sault Electric Company
We Power	W.E. Power, LLC
Wisconsin Energy	Wisconsin Energy Corporation
Wisconsin Gas	Wisconsin Gas LLC

Significant Assets

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

Other Affiliates

ERS	Elm Road Services, LLC
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Federal and State Regulatory Agencies

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

Environmental Terms

ANPR	Advanced Notice of Proposed Rulemaking
BART	Best Available Retrofit Technology
BTA	Best Technology Available
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CAVR	Clean Air Visibility Rule
CWA	Clean Water Act
NAAQS	National Ambient Air Quality Standards
NO _x	Nitrogen Oxide
PM _{2.5}	Fine Particulate Matter
RACT	Reasonably Available Control Technology
SIP	State Implementation Plan
SO ₂	Sulfur Dioxide
WPDES	Wisconsin Pollution Discharge Elimination System

DEFINITION OF ABBREVIATIONS AND INDUSTRY TERMS - (Cont'd)

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

Other Terms and Abbreviations

ARRs	Auction Revenue Rights
Bechtel	Bechtel Power Corporation
Compensation Committee	Compensation Committee of the Board of Directors of Wisconsin Energy
CPCN	Certificate of Public Convenience and Necessity
Energy Policy Act	Energy Policy Act of 2005
FNTP	Full Notice to Proceed
FTRs	Financial Transmission Rights
LMP	Locational Marginal Price
LSEs	Load Serving Entities
MISO	Midwest Independent Transmission System Operator, Inc.
MISO Energy Markets	MISO Energy and Operating Reserves Markets
OTC	Over-the-Counter
Point Beach	Point Beach Nuclear Power Plant
PTF	<i>Power the Future</i>
RSG	Revenue Sufficiency Guarantee
RTO	Regional Transmission Organization

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
CWIP	Construction Work in Progress
FASB	Financial Accounting Standards Board
FIN	FASB Interpretation
FSP	FASB Staff Position
GAAP	Generally Accepted Accounting Principles
OPEB	Other Post-Retirement Employee Benefits
SFAS	Statement of Financial Accounting Standards

Accounting Pronouncements

FIN 46	Consolidation of Variable Interest Entities
FIN 46(R)	Consolidation of Variable Interest Entities (Revised 2003)
FSP FIN 46(R)-8	Disclosures about Consolidation of Variable Interest Entities
SFAS 71	Accounting for the Effects of Certain Types of Regulation
SFAS 123R	Share-Based Payment (Revised 2004)
SFAS 133	Accounting for Derivative Instruments and Hedging Activities
SFAS 149	Amendment of SFAS 133 on Derivative Instruments and Hedging Activities
SFAS 157	Fair Value Measurements
SFAS 160	Noncontrolling Interests in Consolidated Financial Statements
SFAS 161	Disclosures about Derivative Instruments and Hedging Activities

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

Certain statements contained in this report are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. These statements are based upon management's current expectations and are subject to risks and uncertainties that could cause our actual results to differ materially from those contemplated in the statements. Readers are cautioned not to place undue reliance on these forward-looking statements. Forward-looking statements include, among other things, statements concerning management's expectations and projections regarding earnings, completion of construction projects, regulatory matters, fuel costs, sources of electric energy supply, coal and gas deliveries, remediation costs, environmental and other capital expenditures, liquidity and capital resources and other matters. In some cases, forward-looking statements may be identified by reference to a future period or periods or by the use of forward-looking terminology such as "anticipates," "believes," "estimates," "expects," "forecasts," "guidance," "intends," "may," "objectives," "plans," "possible," "potential," "projects" or similar terms or variations of these terms.

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

- Factors affecting utility operations such as unusual weather conditions; catastrophic weather-related or terrorism-related damage; availability of electric generating facilities; unscheduled generation outages, or unplanned maintenance or repairs; unanticipated events causing scheduled generation outages to last longer than expected; unanticipated changes in fossil fuel, purchased power, coal supply, gas supply or water supply costs or availability due to higher demand, shortages, transportation problems or other developments; nonperformance by electric energy or natural gas suppliers under existing power purchase or gas supply contracts; environmental incidents; electric transmission or gas pipeline system constraints; unanticipated organizational structure or key personnel changes; collective bargaining agreements with union employees or work stoppages; or inflation rates.
- Factors affecting the economic climate in our service territories such as customer growth; customer business conditions, including demand for their products and services; and changes in market demand and demographic patterns.
- Timing, resolution and impact of pending and future rate cases and negotiations, including recovery for new investments as part of Wisconsin Energy's PTF strategy, environmental compliance, transmission service, fuel costs and costs associated with the implementation of the MISO Energy Markets.
- Regulatory factors such as changes in rate-setting policies or procedures; changes in regulatory accounting policies and practices; industry restructuring initiatives; transmission or distribution system operation and/or administration initiatives; required changes in facilities or operations to reduce the risks or impacts of potential terrorist activities; required approvals for new construction; and the siting approval process for new generation and transmission facilities and new pipeline construction.
- Increased competition in our electric and gas markets and continued industry consolidation.

**CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION -
(Cont'd)**

- Factors which impede or delay execution of Wisconsin Energy's PTF strategy, including the adverse interpretation or enforcement of permit conditions by the permitting agencies; construction delays; and obtaining the investment capital from outside sources necessary to implement the strategy.
- Factors which may affect successful implementation of the settlement agreement with the two parties who were challenging the WPDES permit for the Oak Creek expansion.
- The impact of recent and future federal, state and local legislative and regulatory changes, including electric and gas industry restructuring initiatives; changes to the Federal Power Act and related regulations under the Energy Policy Act and enforcement thereof by 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; and changes in the application of existing laws and regulations.
- The cost and other effects of legal and administrative proceedings, settlements, investigations, claims and changes in those matters.
- Impacts of the significant contraction in the global credit markets affecting 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 our subsidiary; and our credit ratings.
- The investment performance of Wisconsin Energy's pension and other post-retirement benefit plans.
- The effect of accounting pronouncements issued periodically by standard setting bodies.
- 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.
- Other business or investment considerations that may be disclosed from time to time in our 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, 2008.

Wisconsin Electric Power Company expressly disclaims any obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

INTRODUCTION

Wisconsin Electric Power Company, a wholly-owned subsidiary of Wisconsin Energy, was incorporated in the state of Wisconsin in 1896. We maintain our principal executive offices in Milwaukee, Wisconsin. Unless qualified by their context when used in this document, the terms Wisconsin Electric, the Company, our, us or we refer to Wisconsin Electric Power Company and its subsidiary, Bostco.

We conduct our operations primarily in three operating segments: an electric utility segment, a natural gas utility segment and a steam utility segment. We serve approximately 1,116,600 electric customers in Wisconsin and the Upper Peninsula of Michigan, approximately 461,000 gas customers in Wisconsin and approximately 470 steam customers in metropolitan Milwaukee, Wisconsin. For further financial information about our business segments, see Management's Discussion and Analysis of Financial Condition and Results of Operations and Note 8 -- Segment Information in the Notes to Consolidated Condensed Financial Statements in this report.

Wisconsin Energy is also the parent company of Wisconsin Gas, a natural gas distribution utility, which serves customers throughout Wisconsin; Edison Sault, an electric utility which serves customers in the Upper Peninsula of Michigan; and We Power, an unregulated company that was formed in 2001 to design, construct, own and lease to us the new generating capacity included in Wisconsin Energy's PTF strategy, which is described further in this report and in our 2008 Annual Report on Form 10-K. We have combined common functions with Wisconsin Gas and operate under the trade name of "We Energies."

Other: Bostco is our non-utility subsidiary that develops and invests in real estate. As of March 31, 2009, Bostco had \$36.5 million of assets.

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 2008 Annual Report on Form 10-K, including the financial statements and notes therein.

PART I -- FINANCIAL INFORMATION**ITEM 1. FINANCIAL STATEMENTS**

WISCONSIN ELECTRIC POWER COMPANY
CONSOLIDATED CONDENSED INCOME STATEMENTS
(Unaudited)

	<u>Three Months Ended March 31</u>	
	<u>2009</u>	<u>2008</u>
	(Millions of Dollars)	
Operating Revenues	\$ 988.4	\$ 985.9
Operating Expenses		
Fuel and purchased power	266.1	338.3
Cost of gas sold	217.2	237.1
Other operation and maintenance	320.4	342.4
Depreciation, decommissioning and amortization	65.9	61.8
Property and revenue taxes	24.9	24.2
Total Operating Expenses	<u>894.5</u>	<u>1,003.8</u>
Amortization of Gain	<u>64.2</u>	<u>159.0</u>
Operating Income	158.1	141.1
Equity in Earnings of Transmission Affiliate	12.5	10.1
Other Income, net	5.9	8.7
Interest Expense, net	<u>25.6</u>	<u>22.8</u>
Income Before Income Taxes	150.9	137.1
Income Taxes	<u>52.1</u>	<u>53.2</u>
Net Income	98.8	83.9
Preferred Stock Dividend Requirement	<u>0.3</u>	<u>0.3</u>
Earnings Available for Common Stockholder	<u>\$ 98.5</u>	<u>\$ 83.6</u>

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

WISCONSIN ELECTRIC POWER COMPANY
CONSOLIDATED CONDENSED BALANCE SHEETS

	(Unaudited)	
	March 31, 2009	December 31, 2008
	(Millions of Dollars)	
<u>Assets</u>		
Property, Plant and Equipment		
In service	\$ 7,597.7	\$ 7,560.3
Accumulated depreciation	(2,763.5)	(2,721.2)
	4,834.2	4,839.1
Construction work in progress	255.6	188.4
Leased facilities, net	975.5	870.2
Net Property, Plant and Equipment	6,065.3	5,897.7
Investments		
Restricted cash	145.0	172.4
Equity investment in transmission affiliate	251.1	243.1
Other	0.4	0.4
Total Investments	396.5	415.9
Current Assets		
Cash and cash equivalents	14.7	28.4
Restricted cash	183.6	214.1
Accounts receivable	302.6	213.4
Accounts receivable from related parties	55.2	64.7
Accrued revenues	163.8	233.1
Materials, supplies and inventories	234.8	296.5
Prepayments	92.8	122.3
Regulatory assets	86.5	69.9
Other	74.1	69.1
Total Current Assets	1,208.1	1,311.5
Deferred Charges and Other Assets		
Regulatory assets	971.1	992.9
Other	126.3	157.4
Total Deferred Charges and Other Assets	1,097.4	1,150.3
Total Assets	\$ 8,767.3	\$ 8,775.4
<u>Capitalization and Liabilities</u>		
Capitalization		
Common equity	\$ 2,639.1	\$ 2,582.8
Preferred stock	30.4	30.4
Long-term debt	1,885.6	1,885.3
Capital lease obligations	1,104.8	991.8
Total Capitalization	5,659.9	5,490.3
Current Liabilities		
Long-term debt and capital lease obligations due currently	10.0	9.3
Short-term debt	189.0	-
Subsidiary note payable to Wisconsin Energy	29.5	29.6
Accounts payable	214.1	289.2
Accounts payable to related parties	75.6	76.2
Accrued taxes	61.2	9.6
Regulatory liabilities	260.2	307.7
Other	208.1	202.7
Total Current Liabilities	1,047.7	924.3
Deferred Credits and Other Liabilities		
Regulatory liabilities	765.8	786.5
Deferred income taxes - long-term	698.3	691.7
Pension and other benefit obligations	334.1	614.3
Other	261.5	268.3
Total Deferred Credits and Other Liabilities	2,059.7	2,360.8
Total Capitalization and Liabilities	\$ 8,767.3	\$ 8,775.4

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

WISCONSIN ELECTRIC POWER COMPANY
CONSOLIDATED CONDENSED STATEMENTS OF CASH FLOWS
(Unaudited)

	Three Months Ended March 31	
	2009	2008
	(Millions of Dollars)	
Operating Activities		
Net income	\$ 98.8	\$ 83.9
Reconciliation to cash		
Depreciation, decommissioning and amortization	68.3	66.5
Amortization of gain	(64.2)	(159.0)
Equity in earnings of transmission affiliate	(12.5)	(10.1)
Distributions from transmission affiliate	10.0	7.3
Deferred income taxes and investment tax credits, net	(7.2)	(9.8)
Contributions to benefit plans	(283.8)	(37.9)
Change in -		
Accounts receivable and accrued revenues	(10.4)	(32.4)
Inventories	61.7	66.3
Other current assets	17.8	21.8
Accounts payable	(75.2)	13.2
Accrued income taxes, net	58.9	62.8
Deferred costs, net	11.5	44.6
Other current liabilities	7.3	7.7
Other, net	33.9	70.7
Cash (Used in) Provided by Operating Activities	(85.1)	195.6
Investing Activities		
Capital expenditures	(118.2)	(158.4)
Investment in transmission affiliate	(5.5)	-
Change in restricted cash	57.9	88.3
Other, net	(6.8)	-
Cash Used in Investing Activities	(72.6)	(70.1)
Financing Activities		
Dividends paid on common stock	(44.9)	(54.3)
Dividends paid on preferred stock	(0.3)	(0.3)
Retirement and repurchase of long-term debt	-	(147.0)
Change in short-term debt	188.9	73.5
Other, net	0.3	0.3
Cash Provided by (Used in) Financing Activities	144.0	(127.8)
Change in Cash and Cash Equivalents	(13.7)	(2.3)
Cash and Cash Equivalents at Beginning of Period	28.4	22.0
Cash and Cash Equivalents at End of Period	\$ 14.7	\$ 19.7

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

WISCONSIN ELECTRIC POWER COMPANY
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 2008 Annual Report on Form 10-K. In the opinion of management, we have included all adjustments, normal and recurring in nature, necessary to a fair presentation of the results of operations, cash flows and financial position in the accompanying income statements, statements of cash flows and balance sheets. The results of operations for the three months ended March 31, 2009 are not necessarily indicative of the results which may be expected for the entire fiscal year 2009 because of seasonal and other factors.

2 -- NEW ACCOUNTING PRONOUNCEMENTS

Fair Value Measurements: In September 2006, the FASB issued SFAS 157. SFAS 157 defines fair value, provides guidance for using fair value to measure assets and liabilities as well as a framework for measuring fair value, and expands disclosures related to fair value measurements. SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007. We partially adopted the provisions of SFAS 157 effective January 1, 2008. We fully adopted the provisions of SFAS 157 effective January 1, 2009. The adoption of SFAS 157 did not have a significant financial impact on our consolidated financial statements. See Note 4 -- Fair Value Measurements for required disclosures.

Noncontrolling Interests in Consolidated Financial Statements: In December 2008, the FASB issued SFAS 160. SFAS 160 is effective for fiscal years beginning on or after December 15, 2008. This statement clarifies that a noncontrolling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. We adopted the provisions of SFAS 160 effective January 1, 2009. The adoption of SFAS 160 did not have any financial impact on our consolidated financial statements.

Disclosures about Derivative Instruments and Hedging Activities: In March 2008, the FASB issued SFAS 161, which amends SFAS 133. SFAS 161 requires qualitative disclosures about objectives and strategies for using derivatives, quantitative disclosures about fair value amounts of gains and losses on derivative instruments, and disclosures about credit-risk-related contingent features in derivative agreements. SFAS 161 is effective for fiscal years beginning after November 15, 2008. We adopted the provisions of SFAS 161 effective January 1, 2009. The adoption of SFAS 161 did not have any financial impact on our consolidated financial statements. See Note 5 -- Derivative Instruments for required disclosures.

3 -- COMMON EQUITY

Share-Based Compensation Expense: For a description of share-based compensation, including Wisconsin Energy stock options, restricted stock and performance units, see Note H -- Common Equity in our 2008 Annual Report on Form 10-K. We utilize the straight-line attribution method for recognizing share-based compensation expense under SFAS 123R. 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 Wisconsin Energy stock options held by our employees during the period.

PART I -- FINANCIAL INFORMATION -- (Cont'd)

The following table summarizes recorded pre-tax share-based compensation expense and the related tax benefit for Wisconsin Energy share-based awards made to our employees and directors for the three months ended March 31:

	<u>2009</u>	<u>2008</u>
	(Millions of Dollars)	
Stock options	\$2.3	\$2.8
Performance units	3.4	1.1
Restricted stock	<u>0.1</u>	<u>0.1</u>
Share-based compensation expense	<u>\$5.8</u>	<u>\$4.0</u>
Related tax benefit	<u>\$2.3</u>	<u>\$1.6</u>

Stock Option Activity: During the first three months of 2009, the Compensation Committee granted 1,129,315 Wisconsin Energy stock options to our employees that had an estimated fair value of \$8.01 per share. During the first three months of 2008, the Compensation Committee granted 1,266,645 Wisconsin Energy stock options to our employees which have an estimated fair value of \$9.39 per share. The following assumptions were used to value the Wisconsin Energy options using a binomial option pricing model:

	<u>2009</u>	<u>2008</u>
Risk-free interest rate	0.3% - 2.5%	2.9% - 3.9%
Dividend yield	3.0%	2.1%
Expected volatility	25.9%	20.0%
Expected forfeiture rate	2.0%	2.0%
Expected life (years)	6.2	6.2

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

The following is a summary of our employees' Wisconsin Energy stock option activity through the three months ended March 31, 2009:

Stock Options	Number of Options	Weighted- Average Exercise Price	Weighted- Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (Millions)
Outstanding as of January 1, 2009	7,423,937	\$37.91		
Granted	1,129,315	\$42.22		
Exercised	(46,317)	\$24.95		
Forfeited	-	\$ -		
Outstanding as of March 31, 2009	<u>8,506,935</u>	\$38.55	6.7	\$40.4
Exercisable as of March 31, 2009	<u>5,046,260</u>	\$33.42	5.2	\$40.4

PART I -- FINANCIAL INFORMATION -- (Cont'd)

The intrinsic value of Wisconsin Energy options exercised by our employees was \$0.9 million and \$1.0 million for the three months ended March 31, 2009 and 2008, respectively. Cash received by Wisconsin Energy from exercises of their options by our employees was \$1.2 million and \$1.7 million for the three months ended March 31, 2009 and 2008, respectively. The actual tax benefit realized for the tax deductions from option exercises during the same periods was \$0.4 million and \$0.3 million, respectively.

The following table summarizes information about Wisconsin Energy stock options held by our employees that are outstanding as of March 31, 2009:

Range of Exercise Prices	Options Outstanding			Options Exercisable		
	Number of Options	Weighted-Average		Number of Options	Weighted-Average	
		Exercise Price	Remaining Contractual Life (Years)		Exercise Price	Remaining Contractual Life (Years)
\$19.62 to \$31.07	1,399,513	\$25.89	3.6	1,399,513	\$25.89	3.6
\$33.44 to \$39.48	3,451,107	\$35.66	5.7	3,451,107	\$35.66	5.7
\$42.22 to \$48.04	<u>3,656,315</u>	\$46.12	8.7	<u>195,640</u>	\$47.80	7.9
	<u>8,506,935</u>	\$38.55	6.7	<u>5,046,260</u>	\$33.42	5.2

The following table summarizes information about our employees' non-vested Wisconsin Energy stock options during the three months ended March 31, 2009:

Non-Vested Stock Options	Number of Options	Weighted-Average Fair Value
Non-vested as of January 1, 2009	3,339,669	\$8.81
Granted	1,129,315	\$8.01
Vested	(1,008,309)	\$7.55
Forfeited	-	\$ -
Non-vested as of March 31, 2009	<u>3,460,675</u>	\$8.72

As of March 31, 2009, our total compensation costs related to non-vested Wisconsin Energy stock options not yet recognized was approximately \$14.4 million, which is expected to be recognized over the next 21 months on a weighted-average basis.

PART I -- FINANCIAL INFORMATION -- (Cont'd)

Restricted Shares: The Compensation Committee has also approved Wisconsin Energy restricted stock grants to certain of our key employees. The following restricted stock activity related to our employees occurred during the three months ended March 31, 2009:

Restricted Shares	Number of Shares	Weighted- Average Grant Date Fair Value
Outstanding as of January 1, 2009	67,328	
Granted	-	\$ -
Released / Forfeited	(1,475)	\$31.79
Outstanding as of March 31, 2009	65,853	

Wisconsin Energy records the market value of the restricted stock awards on the date of grant. We then amortize our share of allocated expense over the vesting period of the awards. We also adjust expense for acceleration of vesting due to achievement of performance goals. The intrinsic value of Wisconsin Energy restricted stock vesting and held by our employees was \$0.1 million and \$0.4 million for the three months ended March 31, 2009 and 2008, respectively. The actual tax benefit realized for the tax deductions from released restricted shares was nearly \$0.1 million during the same periods.

As of March 31, 2009, total compensation cost related to our share of Wisconsin Energy restricted stock not yet recognized was approximately \$0.8 million, which is expected to be recognized over the next 44 months on a weighted-average basis.

Performance Units: In January 2009 and 2008, the Compensation Committee granted 309,310 and 124,175 Wisconsin Energy performance units, respectively, to our 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 Wisconsin Energy's stock over a three year period. We are accruing our share of compensation costs over the three year period based on our estimate of the final expected value of the award. Wisconsin Energy performance units earned as of December 31, 2008 and 2007 vested and were settled during the first quarter of 2009 and 2008, and had a total intrinsic value of \$7.8 million and \$4.7 million, respectively.

The actual tax benefit realized for the tax deductions from the settlement of performance units was approximately \$2.9 million and \$1.6 million, respectively. As of March 31, 2009, total compensation cost related to performance units not yet recognized was approximately \$18.0 million, which is expected to be recognized over the next 27 months on a weighted-average basis.

Restrictions: Various financing arrangements and regulatory requirements impose certain restrictions on our ability to transfer funds to Wisconsin Energy in the form of cash dividends, loans or advances. In addition, under Wisconsin law, we are prohibited from loaning funds, either directly or indirectly, to Wisconsin Energy. See Note H -- Common Equity in our 2008 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 normal dividend payments in the foreseeable future.

PART I -- FINANCIAL INFORMATION -- (Cont'd)

Comprehensive Income: Comprehensive income includes all changes in equity during a period except those resulting from investments by and distributions to owners. During the three months ended March 31, 2009 and 2008, total comprehensive income was equal to net income.

4 -- FAIR VALUE MEASUREMENTS

We adopted SFAS 157 as of January 1, 2008, which among other things, requires enhanced disclosures about assets and liabilities that are measured and reported at fair value. SFAS 157 establishes a hierarchical disclosure framework which prioritizes and ranks the level of observable inputs used in measuring fair value.

As defined in SFAS 157, 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 established under SFAS 157 gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement).

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 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 SFAS 157 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.

PART I -- FINANCIAL INFORMATION -- (Cont'd)

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

Recurring Fair Value Measures	As of March 31, 2009			
	Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Assets:				
Restricted Cash	\$328.6	\$ -	\$ -	\$328.6
Derivatives	-	4.3	2.9	7.2
Total	\$328.6	\$4.3	\$2.9	\$335.8
Liabilities:				
Derivatives	\$40.9	\$5.1	\$ -	\$46.0
Total	\$40.9	\$5.1	\$ -	\$46.0

Recurring Fair Value Measures	As of December 31, 2008			
	Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Assets:				
Cash Equivalents	\$8.0	\$ -	\$ -	\$8.0
Restricted Cash	386.5	-	-	386.5
Derivatives	-	4.1	8.8	12.9
Total	\$394.5	\$4.1	\$8.8	\$407.4
Liabilities:				
Derivatives	\$34.0	\$15.3	\$ -	\$49.3
Total	\$34.0	\$15.3	\$ -	\$49.3

Cash Equivalents consist of certificates of deposit and money market funds. Restricted cash consists of certificates of deposit and government backed interest bearing securities and represents the remaining funds to be distributed to customers resulting from the net proceeds received from the sale of Point Beach. 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.

PART I -- FINANCIAL INFORMATION -- (Cont'd)

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

Fair Value of Derivatives	2009	2008
	(Millions of Dollars)	
Balance as of January 1	\$8.8	\$13.0
Realized and unrealized gains (losses)	-	-
Settlements	(5.9)	(8.5)
Transfers in and/or out of Level 3	-	-
Balance as of March 31	\$2.9	\$4.5
Change in unrealized gains (losses) relating to instruments still held as of March 31	\$ -	\$ -

Derivative instruments reflected in Level 3 of the hierarchy include FTRs allocated by MISO 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 in accordance with SFAS 71. See Note 5 -- Derivative Instruments for further information on the offset to regulatory assets and liabilities.

5 -- DERIVATIVE INSTRUMENTS

We follow SFAS 133, as amended by SFAS 149, which requires that every derivative instrument be recorded on the balance sheet as an asset or liability measured at its fair value and that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. For most energy related physical and financial contracts in our regulated operations that qualify as derivatives under SFAS 133, the PSCW allows the effects of the fair market value accounting to be offset to regulatory assets and liabilities in accordance with SFAS 71. 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 March 31, 2009, we recognized \$58.6 million in regulatory assets and \$7.2 million in regulatory liabilities related to derivatives.

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. Our approach is non-speculative and designed to mitigate risk and protect against price volatility. Regulated hedging programs require prior approval by the PSCW.

PART I -- FINANCIAL INFORMATION -- (Cont'd)

We record our derivative assets on the balance sheet in Other current assets and the current portion of the liabilities in Other current liabilities. The long-term portion of our derivative liability is recorded in Other deferred credits and liabilities. Our Consolidated Condensed Balance Sheet as of March 31, 2009 includes:

	Derivative Asset	Derivative Liability
	(Millions of Dollars)	
Natural Gas	\$0.1	\$42.3
Energy	-	0.3
Fuel Oil	-	1.7
FTRs	2.9	-
Coal	4.2	1.7
Total	<u>\$7.2</u>	<u>\$46.0</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 quarter ended March 31, 2009 follow:

	Volume	Gains (Losses)
		(Millions of Dollars)
Natural Gas	11.2 million Dth	(\$17.2)
Energy	11,920 MWh purchased	(0.5)
Fuel Oil	1.26 million gallons	(0.9)
FTRs	6,251 MW	(4.7)
Coal	110,000 tons	(0.5)
Total		<u>(\$23.8)</u>

The aggregate fair value of all derivative instruments with credit-risk-related contingent features that are in a liability position as of March 31, 2009 is \$46.0 million for which we have posted collateral of \$52.0 million in the normal course of business. If the credit-risk-related contingent features underlying these agreements were triggered, we would be covered by the collateral in our margin accounts.

PART I -- FINANCIAL INFORMATION -- (Cont'd)**6 -- BENEFITS**

The components of our net periodic pension and OPEB costs for the three months ended March 31 were as follows:

Benefit Plan Cost Components	Pension Benefits		OPEB	
	2009	2008	2009	2008
	(Millions of Dollars)			
Net Periodic Benefit Cost				
Service cost	\$5.2	\$4.4	\$2.1	\$2.5
Interest cost	15.5	14.7	4.2	4.1
Expected return on plan assets	(18.2)	(15.3)	(2.3)	(2.7)
Amortization of:				
Transition obligation	-	-	0.1	0.1
Prior service cost (credit)	0.6	0.5	(3.2)	(3.1)
Actuarial loss	3.4	2.3	1.4	1.3
Net Periodic Benefit Cost	<u>\$6.5</u>	<u>\$6.6</u>	<u>\$2.3</u>	<u>\$2.2</u>

As of December 31, 2008, the returns on Wisconsin Energy's pension and OPEB plan assets were significantly below the expected rate of return of 8.5%. In January 2009, we contributed \$283.8 million to Wisconsin Energy's 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.

In January 2009, the committee that oversees the investment of the pension assets authorized the Plan Trustee to invest in the commercial paper of Wisconsin Energy. As of March 31, 2009, the Pension Trust held approximately \$90 million of commercial paper issued by Wisconsin Energy.

7 -- GUARANTEES

We enter into various guarantees to provide financial and performance assurance to third parties. As of March 31, 2009, we had the following guarantees:

Maximum Potential Future Payments	Outstanding	Liability Recorded
	(Millions of Dollars)	
\$2.9	\$0.1	\$ -

We are subject to the potential retrospective premiums that could be assessed under our insurance program.

Postemployment Benefits: Postemployment benefits provided to former or inactive employees are recognized when an event occurs. The estimated liability, excluding severance benefits, for such benefits was \$13.6 million as of March 31, 2009 and \$13.0 million as of December 31, 2008.

PART I -- FINANCIAL INFORMATION -- (Cont'd)**8 -- SEGMENT INFORMATION**

Summarized financial information concerning our reportable operating segments for the three month periods ended March 31, 2009 and 2008 is shown in the following table:

	<u>Reportable Operating Segments</u>			<u>Total</u>
	<u>Electric</u>	<u>Gas</u>	<u>Steam</u>	
<u>Three Months Ended</u>	<u>(Millions of Dollars)</u>			
March 31, 2009				
Operating Revenues (a)	\$685.7	\$287.5	\$15.2	\$988.4
Operating Income	\$114.8	\$37.8	\$5.5	\$158.1
March 31, 2008				
Operating Revenues (a)	\$660.4	\$310.2	\$15.3	\$985.9
Operating Income	\$92.6	\$42.2	\$6.3	\$141.1

(a) We account for all intersegment revenues at tariff rates established by the PSCW. Intersegment revenues were not material.

9 -- VARIABLE INTEREST ENTITIES

Under FIN 46 and FIN 46(R), the primary beneficiary of a variable interest entity must consolidate the related assets and liabilities. In December 2008, the FASB issued FSP FIN 46(R)-8 requiring additional disclosures 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 as prescribed by FIN 46(R). 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 but have been unable to determine if we are the primary beneficiary of these two variable interest entities as defined by FIN 46(R). The requested information required to make this determination has not been supplied. As a result, we do not consolidate these entities. Instead, we account for one of these contracts as a capital lease and the other contract as an operating lease. We have approximately \$459.8 million of required payments over the remaining terms of these two agreements, which expire over the next 14 years. We believe the required payments or any replacement power purchased will continue to be recoverable in rates. Total capacity and minimum lease payments under these contracts for the periods ended March 31, 2009 and December 31, 2008 were \$14.1 million and \$66.4 million, respectively.

PART I -- FINANCIAL INFORMATION -- (Cont'd)

10 -- 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.

Indemnifications: In connection with the sale of Point Beach, we agreed to provide the buyer with indemnification provisions customary to transactions involving the sale of nuclear assets.

11 -- SUPPLEMENTAL CASH FLOW INFORMATION

During the three months ended March 31, 2009, we paid \$0.5 million in interest, net of amounts capitalized, and we did not pay any income taxes, net of refunds. During the three months ended March 31, 2008, we paid \$4.3 million in interest, net of amounts capitalized, and we did not pay any income taxes, net of refunds.

As of March 31, 2009 and 2008, the amount of accounts payable related to capital expenditures was \$21.8 million and \$7.5 million, respectively.

PART I -- FINANCIAL INFORMATION -- (Cont'd)**ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS****RESULTS OF OPERATIONS -- THREE MONTHS ENDED MARCH 31, 2009****EARNINGS**

We had net income of \$98.8 million for the first quarter of 2009, an increase of \$14.9 million, or 17.8%, from the first quarter of 2008. A more detailed analysis of our financial results follows.

Our operating income was \$158.1 million for the first quarter of 2009, an increase of \$17.0 million, or 12.0%, from the first quarter of 2008. The increase in operating income was primarily caused by favorable recoveries of revenues associated with fuel and purchased power. During the first quarter of 2009, we experienced favorable fuel recoveries of approximately \$28 million. During the same period in 2008, we experienced unfavorable fuel recoveries of approximately \$14 million. While we experienced a net \$42 million positive increase in fuel recoveries in the first quarter 2009 as compared to the same period in 2008, we expect a substantial portion of the favorable fuel recoveries to reverse by the end of the year as a result of a request we filed with the PSCW to reduce Wisconsin retail electric rates for calendar year 2009. For additional information on the rate filing, see Factors Affecting Results, Liquidity and Capital Resources -- Rates and Regulatory Matters -- 2009 Fuel Cost Decrease Filing.

In January 2008, we received a rate order from the PSCW that authorized a 17.2% increase in electric rates to recover increased costs associated with transmission expenses, Wisconsin Energy's PTF program, environmental expenditures, continued investment in renewable and efficiency programs and recovery of previously deferred regulatory assets. The PSCW allowed us to issue bill credits to our customers from the proceeds of the net gain and excess decommissioning funds associated with the sale of Point Beach to mitigate this increase. The PSCW also determined that \$85.0 million of Point Beach proceeds should be immediately applied to offset certain regulatory assets. As a result of these bill credits, we estimate that the January 2008 PSCW rate order resulted in a net 3.2% increase in electric rates paid by our Wisconsin customers in 2008 and resulted in another net increase of 3.2% in 2009. The bill credits that we issue to our customers and the proceeds immediately applied to regulatory assets are reflected on our income statement in the amortization of the gain on the sale of Point Beach. As we issue the bill credits, we transfer the cash from a restricted account to an unrestricted account. The transferred cash is equal to the bill credits, less taxes.

PART I -- FINANCIAL INFORMATION -- (Cont'd)**Electric Utility Revenues and Sales**

The following table compares electric utility operating revenues and MWh sales by customer class during the three months ended March 31 including favorable (better (B)) or unfavorable (worse (W)) variances:

Electric Utility Operations	Electric Revenues			MWh Sales		
	2009	B(W)	2008	2009	B(W)	2008
	(Millions of Dollars)			(Thousands)		
Customer Class						
Residential	\$257.4	\$14.8	\$242.6	2,073.1	(80.3)	2,153.4
Small Commercial/Industrial	222.1	16.9	205.2	2,221.9	(52.1)	2,274.0
Large Commercial/Industrial	141.6	(10.9)	152.5	2,192.2	(483.8)	2,676.0
Other - Retail	5.6	0.2	5.4	40.8	(2.1)	42.9
Total Retail	626.7	21.0	605.7	6,528.0	(618.3)	7,146.3
Wholesale - Other	34.9	(4.2)	39.1	574.9	(153.9)	728.8
Resale - Utilities	18.0	12.2	5.8	477.1	280.9	196.2
Other Operating Revenues	6.1	(3.7)	9.8	-	-	-
Total	\$685.7	\$25.3	\$660.4	7,580.0	(491.3)	8,071.3

Weather -- Degree Days (a)

Heating (3,240 Normal)	3,458	(95)	3,553
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- (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 \$25.3 million, or 3.8%, when compared to the first quarter of 2008. We estimate that our first quarter 2009 revenues were \$57.3 million higher than the first quarter of 2008 due to pricing increases that we received during January 2008 as part of the 2008 PSCW rate case that were in effect for a full quarter in 2009, as well as pricing increases related to fuel that we received in a final fuel order from the PSCW in July 2008. For more information on the pricing increases, see Rates and Regulatory Matters in Factors Affecting Results, Liquidity and Capital Resources below. We also estimate that our electric revenues increased by \$9.8 million as a result of fewer bill credits to our customers from the sale of Point Beach during the first quarter of 2009 as compared to the same period in 2008. For more information on bill credits, see Amortization of Gain in Results of Operations. These increases were partially offset by a \$10 million decrease in electric revenues related to MISO RSG credits that may be received during 2009. For more information on the MISO RSG credits, see Factors Affecting Results, Liquidity and Capital Resources -- Rates and Regulatory Matters -- 2008 Fuel Recovery Request.

Our total electric sales volumes decreased by approximately 6.1%, with retail sales volumes declining nearly 8.7%. Of the 8.7% decline in retail sales volumes, approximately 7.5% relates to sales volumes at our small and large commercial and industrial customers. The primary reason for the reduced sales volumes relates to a decline in economic conditions during the first quarter of 2009 as compared to the same period in 2008. Additionally, milder weather during the first three months of 2009 as compared to the same period in 2008 reduced revenues by approximately \$2.2 million. As measured by heating degree days, the first quarter of 2009 was 2.7% warmer than the first quarter of 2008.

For 2009, we expect to see a continued decline in electric sales to commercial and industrial customers as compared to 2008 as a result of the downturn in the economy. We also expect to see a reduction in revenues because of the April 2009 fuel cost decrease filing, which is expected to reduce annual revenues

PART I -- FINANCIAL INFORMATION -- (Cont'd)

by \$67.2 million. For more information on the fuel cost decrease filing, see Factors Affecting Results, Liquidity and Capital Resources -- Rates and Regulatory Matters -- 2009 Fuel Cost Decrease Filing.

Fuel and Purchased Power

Our fuel and purchased power costs decreased by \$72.2 million, or 21.3%, when compared to the first quarter of 2008. The largest factor related to this decrease was the one-time amortization of deferred fuel costs of \$41.2 million that occurred in January 2008. Adjusted for the one-time amortization, our fuel and purchased power costs decreased by \$31.0 million, or 9.2%. This decline was caused by lower MWh sales as well as lower natural gas and purchased power prices, partially offset by higher coal and related transportation costs.

Gas Utility Revenues, Gross Margin and Therm Deliveries

A comparison follows of gas utility operating revenues, gross margin and gas deliveries during the first quarter of 2009 with similar information for the first quarter of 2008. 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 revenues decreased by \$22.7 million, or 7.3%, primarily due to milder weather and lower gas prices.

Gas Utility Operations	Three Months Ended March 31		
	2009	B (W)	2008
	(Millions of Dollars)		
Gas Operating Revenues	\$287.5	(\$22.7)	\$310.2
Cost of Gas Sold	217.2	19.9	237.1
Gross Margin	<u>\$70.3</u>	<u>(\$2.8)</u>	<u>\$73.1</u>

The following table compares our gas utility gross margin and therm deliveries by customer class during the three months ended March 31:

Gas Utility Operations	Gross Margin			Therm Deliveries		
	2009	B (W)	2008	2009	B (W)	2008
	(Millions of Dollars)			(Millions)		
Customer Class						
Residential	\$46.7	(\$1.8)	\$48.5	169.9	(8.4)	178.3
Commercial/Industrial	18.1	(0.6)	18.7	100.1	(4.1)	104.2
Interruptible	0.2	(0.1)	0.3	2.5	(0.2)	2.7
Total Retail	65.0	(2.5)	67.5	272.5	(12.7)	285.2
Transported Gas	4.5	(0.4)	4.9	91.6	(10.6)	102.2
Other	0.8	0.1	0.7	-	-	-
Total	<u>\$70.3</u>	<u>(\$2.8)</u>	<u>\$73.1</u>	<u>364.1</u>	<u>(23.3)</u>	<u>387.4</u>
Weather -- Degree Days (a)						
Heating (3,240 Normal)				3,458	(95)	3,553

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

PART I -- FINANCIAL INFORMATION -- (Cont'd)

Our gas margin decreased by \$2.8 million, or approximately 3.8%, when compared to the first quarter of 2008. We estimate that approximately \$1.6 million of this decrease relates to a decline in sales volumes as a result of milder winter weather during the first quarter of 2009 as compared to the first quarter of 2008. As measured by heating degree days, the first three months of 2009 were 2.7% warmer than the same period in 2008 and 6.7% cooler than normal.

Other Operation and Maintenance Expense

Our other operation and maintenance expense decreased by \$22.0 million, or approximately 6.4%, when compared to the first quarter of 2008. The largest factor for this decrease relates to a \$43.8 million one-time amortization of deferred bad debt costs in connection with the January 2008 PSCW rate order, which we recorded during the first quarter of 2008. The January 2008 PSCW rate order, which was in effect for a full quarter in 2009, allowed for pricing increases related to transmission costs, PTF lease costs and the amortization of other deferred costs. We estimate that these items were approximately \$15.0 million higher in the first quarter of 2009 as compared to the same period in 2008.

Depreciation, Decommissioning and Amortization Expense

Our depreciation, decommissioning and amortization expense increased by \$4.1 million, or approximately 6.6%, when compared to the first quarter of 2008. This increase is the result of higher depreciation related to new projects, including the Blue Sky Green Field wind project that was placed in service in May 2008.

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 of approximately \$902.2 million to be used for the benefit of our customers. The majority of the benefits are being returned to customers in the form of bill credits. The net gain was originally recorded as a regulatory liability, and it is being amortized to the income statement as we issue bill credits or make refunds to our customers. When the bill credits and refunds are issued to customers, we transfer cash from the restricted accounts to the unrestricted accounts, adjusted for taxes.

The following table compares the amortization of the gain during the three months ended March 31:

Amortization of Gain	2009	2008
	(Millions of Dollars)	
Bill Credits - Retail	\$64.2	\$74.0
One-Time Amortization	-	85.0
Total Amortization of Gain	\$64.2	\$159.0

For the remainder of 2009, we expect to see a reduction in the Amortization of Gain as compared to 2008 because of the one-time entry identified above and a one-time \$62.5 million FERC approved refund to our wholesale customers in 2008, as well as an approximate \$100 million annual decrease in bill credits to retail customers.

PART I -- FINANCIAL INFORMATION -- (Cont'd)**Other Income, net**

Other income, net decreased by \$2.8 million, or approximately 32.2%, when compared to the first quarter of 2008. This decline primarily relates to reduced property sales during the first quarter of 2009 as compared to the same period in 2008.

Interest Expense, net

<u>Interest Expense, net</u>	<u>Three Months Ended March 31</u>	
	<u>2009</u>	<u>2008</u>
	(Millions of Dollars)	
Gross Interest Costs	\$26.8	\$23.9
Less: Capitalized Interest	<u>1.2</u>	<u>1.1</u>
Interest Expense, net	<u><u>\$25.6</u></u>	<u><u>\$22.8</u></u>

Our gross interest costs increased by \$2.9 million in 2009 primarily due to higher debt balances as compared to the same period in 2008. Our capitalized interest increased by \$0.1 million. As a result, our net interest expense increased by \$2.8 million, or 12.3%, as compared to the first quarter of 2008.

Income Taxes

For the first quarter of 2009, our effective tax rate was 34.5% compared to 38.8% for the first quarter of 2008.

LIQUIDITY AND CAPITAL RESOURCES**CASH FLOWS**

The following summarizes our cash flows during the three months ended March 31:

	<u>2009</u>	<u>2008</u>
	(Millions of Dollars)	
Cash Provided by (Used in)		
Operating Activities	(\$85.1)	\$195.6
Investing Activities	(\$72.6)	(\$70.1)
Financing Activities	\$144.0	(\$127.8)

Operating Activities

Cash used in operating activities was \$85.1 million during the three months ended March 31, 2009 compared to \$195.6 million provided by operating activities during the same period in 2008. Although we experienced an increase in net income during the first quarter of 2009, there was one significant item that reduced operating cash flows. In the first quarter of 2009, we contributed \$283.8 million to Wisconsin Energy's benefit plans compared to \$37.9 million in the first quarter of 2008, which resulted in a \$245.9 million decrease in operating cash flows.

PART I -- FINANCIAL INFORMATION -- (Cont'd)**Investing Activities**

Cash used in investing activities was \$72.6 million during the three months ended March 31, 2009, which was \$2.5 million higher than the same period in 2008. The increase primarily reflects a reduction in the release of restricted cash and an increased investment in our transmission affiliate. This increase was partially offset by lower capital expenditures during the first quarter of 2009.

During the first quarter of 2009, we released \$30.4 million less from restricted cash as compared to the same period in 2008. In September 2007, we sold Point Beach and placed approximately \$924 million of cash in restricted accounts to be used for the payment of taxes and for the benefit of our customers. We release the restricted cash, adjusted for taxes, as we issue bill credits to our customers, which is reflected as an amortization of the gain on our income statement.

During the first quarter of 2009, our capital expenditures decreased by \$40.2 million as compared to the same period last year primarily due to the completion of our Blue Sky Green Field wind project in 2008.

Financing Activities

Cash provided by financing activities was \$144.0 million during the three months ended March 31, 2009 compared to \$127.8 million used in financing activities during the same period in 2008. During the first quarter of 2009, we increased our debt levels by approximately \$188.9 million compared to a \$73.5 million reduction in our debt levels during the same period in 2008.

CAPITAL RESOURCES AND REQUIREMENTS**Capital Resources**

We anticipate meeting our capital requirements during the remaining nine months of 2009 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, and an equity contribution from our parent. Beyond 2009, we anticipate meeting our capital requirements through internally generated funds supplemented, when required, by short-term borrowings, the issuance of debt securities and equity contributions from our parent.

Despite the continued turmoil in the global credit markets, we still 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 arrangement, access to capital markets and internally generated cash.

We maintain a bank back-up credit facility that provides liquidity support for our obligations with respect to commercial paper and for general corporate purposes.

An affiliate of Lehman Brothers Holdings, which filed for bankruptcy in September 2008, committed approximately \$23.6 million under our bank back-up credit facility. We have no current plans to replace Lehman's commitment. Excluding Lehman's commitment, as of March 31, 2009, we had approximately \$472.3 million of available, undrawn lines under our bank back-up credit facility. As of March 31, 2009,

PART I -- FINANCIAL INFORMATION -- (Cont'd)

we had approximately \$189.0 million of short-term debt outstanding that was supported by the available lines of credit.

We review our bank back-up credit facility needs on an ongoing basis and expect to be able to maintain adequate credit facilities to support our operations. The following table summarizes such facility as of March 31, 2009:

<u>Total Facility *</u>	<u>Letters of Credit</u>	<u>Credit Available *</u>	<u>Facility Expiration</u>
(Millions of Dollars)			
\$476.4	\$4.1	\$472.3	March 2011

* Excludes Lehman's commitment

Capital Requirements

Capital requirements during the remainder of 2009 are expected to be principally for capital expenditures related to our electric distribution system and environmental controls at our existing Oak Creek generating units. Our 2009 annual capital expenditure budget is approximately \$600 million.

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 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 7 -- Guarantees and Note 9 -- 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 \$22.3 billion as of March 31, 2009 compared with \$21.9 billion as of December 31, 2008. Our total contractual obligations and other commercial commitments as of March 31, 2009 increased compared with December 31, 2008 primarily due to increased capital lease obligations related to the Oak Creek water intake system that was placed into service in January 2009.

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 2008 Annual Report on Form 10-K, which provides a more complete discussion of factors affecting us, including market risks and other significant risks, Wisconsin Energy's PTF strategy, rates and regulatory matters, electric system reliability, environmental matters, legal matters, industry restructuring and competition and other matters.

PART I -- FINANCIAL INFORMATION -- (Cont'd)**POWER THE FUTURE**

Under Wisconsin Energy's PTF strategy, we expect to meet a significant portion of our future generation needs through the leasing of the PWGS and the Oak Creek expansion, which are being constructed by We Power. We will lease the new units from We Power under long-term leases, and we expect to recover the lease payments in our electric rates. See Factors Affecting Results, Liquidity and Capital Resources -- Power the Future in Item 7 of our 2008 Annual Report on Form 10-K for additional information on PTF.

Oak Creek Expansion

Construction Status: In July 2008, Bechtel, the contractor of the Oak Creek expansion under a fixed price contract, notified We Power in a letter that it forecasts the in-service date of unit 1 to be delayed three months beyond the guaranteed contract date of September 29, 2009. Bechtel also advised We Power in the letter that it forecasts the in-service date of unit 2 to be one month earlier than the guaranteed contract date of September 29, 2010.

We Power received Bechtel's claims for schedule and cost relief on December 22, 2008. Although Bechtel did not change the forecasted in-service dates, it did request schedule relief that would result in six months of relief from liquidated damages beyond the guaranteed contract date for unit 1 and three months of relief from liquidated damages beyond the guaranteed contract date for unit 2. Bechtel's claims are based on the alleged effects of severe winter weather and certain labor-related matters, as well as the alleged effects of ERS-directed changes and delays allegedly caused by ERS prior to the issuance of the FNTF in 2005.

Based on Bechtel's July 2008 communication, We Power notified Bechtel on September 29, 2008 that it was invoking the formal dispute resolution process provided in the contract in order to resolve certain issues related to the rights of the parties under the contract. We Power has since agreed with Bechtel to combine these issues and Bechtel's claim into one mediation. We Power anticipates mediating all issues before the end of the year and if this is unsuccessful, the contract calls for binding arbitration which We Power anticipates will be concluded in 2010.

Bechtel continues to target an in-service date for unit 1 three months beyond the guaranteed contract date of September 29, 2009, and an in-service date for unit 2 one month earlier than the guaranteed contract date of September 29, 2010. Although Bechtel has made significant progress in much of the construction plan, it has fallen behind in moving from construction to start-up. Bechtel has informed We Power that it has developed a recovery plan and is adding resources in an effort to recover the lost time.

RATES AND REGULATORY MATTERS

2010 Rate Case: On March 13, 2009, we initiated rate proceedings with the PSCW. We have asked the PSCW to approve a rate increase for our Wisconsin retail electric customers of approximately \$76.5 million, or 2.8%, and a rate increase for our natural gas customers of approximately \$22.1 million, or 3.6%. In addition, we have requested increases of approximately \$1.4 million, or 5.8%, and approximately \$1.3 million, or 6.8%, for our Valley steam utility customers and Milwaukee County steam utility customers, respectively. We have requested that these rates become effective January 1, 2010.

PART I -- FINANCIAL INFORMATION -- (Cont'd)

As part of our electric rate proceeding, we have asked the PSCW to make the following determinations:

- New proposed depreciation rates will become effective prior to or concurrent with the implementation of the new base rates requested in the proceeding.
- Certain regulatory assets currently scheduled to be fully amortized over the next four years will instead be amortized over the next eight years.
- We will continue to receive 100% AFUDC for capital expenditures on environmental control projects at our Oak Creek power plant, as well as 100% AFUDC for capital expenditures on an environmental control project at Edgewater 5 and on renewable energy projects including the proposed Glacier Hills Wind Park.
- If recommendations of the Wisconsin Governor's Task Force on Global Warming are enacted, we will have the option of applying for a limited reopener or for deferral accounting to address any increased costs or reduced sales that result from such enactment.

2009 Fuel Cost Decrease Filing: We operate under a fuel cost adjustment clause for fuel and purchased power costs associated with the generation and delivery of electricity to our retail customers in Wisconsin. Based on three months of actual fuel cost data and nine months of projected data, we forecast that our monitored fuel cost for 2009 will fall outside the range prescribed by the PSCW and will be less than the monitored fuel cost reflected in currently authorized rates. Therefore, in April 2009, we filed a request with the PSCW to decrease annual Wisconsin retail electric rates by \$67.2 million for calendar year 2009. On April 30, 2009, the PSCW approved the fuel cost decrease filing with rates effective May 1, 2009.

2008 Pricing: During 2007, we initiated rate proceedings. We asked the PSCW to approve a comprehensive plan which would result in price increases of \$648.6 million for our electric customers in Wisconsin. This price increase would be reduced by expected bill credits resulting from the sale of Point Beach. The initial rate filing estimated bill credits of \$371.0 million in 2008 and \$187.5 million in 2009, resulting in net pricing increases of 7.5% in 2008 and 7.5% in 2009. In addition, we requested a 1.8% price increase in 2008 for our gas customers and an approximately 16.0% price increase in 2008 for all steam customers in Milwaukee.

Electric pricing increases were needed to allow us to continue progress on previously approved initiatives, including: costs associated with the new PTF plants; recovery of costs associated with transmission; compliance with environmental regulations; continuation of investment in renewable and efficiency programs, including the Blue Sky Green Field wind project; and scheduled recovery of regulatory assets.

On January 17, 2008, the PSCW approved pricing increases for us as follows:

- \$389.1 million (17.2%) in electric rates - the pricing increase will be offset by \$315.9 million in bill credits in 2008 and \$240.7 million in bill credits in 2009, resulting in a net increase of \$73.2 million (3.2%) and \$75.2 million (3.2%), respectively;
- \$4.0 million (0.6%) for natural gas service; and
- \$3.6 million (11.2%) for steam service.

In addition, the PSCW lowered our return on equity from 11.2% to 10.75%. The PSCW also determined that \$85.0 million of the Point Beach proceeds should be immediately applied to offset certain regulatory assets.

PART I -- FINANCIAL INFORMATION -- (Cont'd)

We expect to provide a total of approximately \$710.0 million of bill credits to our Wisconsin customers over the three year period ending December 31, 2010. As of March 31, 2009, we have issued approximately \$352.3 million of bill credits to Wisconsin retail customers.

Michigan Price Increase: In January 2008, we filed a rate increase request with the MPSC. This request represents an increase in electric rates of 14.7%, or \$22.0 million, to support the growing demand for electricity, continued investment in renewable programs, compliance with environmental regulations, addition of distribution infrastructure and increased operational expenses. In November 2008, a settlement agreement with the MPSC staff and intervenors for a rate increase of \$7.2 million, or 4.6%, was approved by the MPSC, effective January 1, 2009.

2008 Fuel Recovery Request: In March 2008, we filed a rate increase request with the PSCW to recover forecasted increases in fuel and purchased power costs. The increase in fuel costs was being driven primarily by increases in the price of natural gas and the higher cost of transporting coal by rail as a result of increases in the cost of diesel fuel. On April 11, 2008, the PSCW approved an annual increase of \$76.9 million (3.3%) in Wisconsin retail electric rates on an interim basis. In July 2008, we received the final rate order, which authorized an additional \$42.0 million in rate increases, for a total increase of \$118.9 million (5.1%). Any over-collection of fuel surcharge revenue in calendar year 2008 was subject to refund with interest at a rate of 10.75%. In April 2009, the PSCW ordered that we should refund \$8.8 million (including interest) of over-collected fuel surcharge revenue that was billed in 2008 plus \$10.0 million of MISO RSG credits that may be received during 2009. We expect to refund approximately \$18.8 million to customers by the end of the second quarter of 2009.

Oak Creek Air Quality Control System Approval: In July 2008, we received approval from the PSCW granting us authority to construct wet flue gas desulfurization and selective catalytic reduction facilities at Oak Creek Power Plant Units 5-8. Construction of these emission controls began in late July 2008, and we expect the installation to be completed during 2012. We originally estimated the cost of this project to be \$750 million (\$830 million including AFUDC). We now expect the cost of completing this project to be approximately \$800 million (\$960 million including AFUDC). The cost increase is primarily attributable to increases in material prices that occurred prior to the commencement of construction and material procurement activities in July 2008. The increase in AFUDC is based on our updated calculation that assumes AFUDC will accrue on 100% of the construction cost until the facilities are placed in service, which is consistent with the 2010 rate case filing. The cost of constructing these facilities is included in our estimates of the costs to implement the Consent Decree with the EPA.

Depreciation Rates: Periodically, we engage consultants to perform depreciation studies on our utility assets to determine our depreciation rates. In 2008, a consultant completed a depreciation study that concluded that we should reduce our utility depreciation rates because of longer asset lives and increased salvage values. The consultant estimated that the new proposed rates would reduce annual depreciation expense by approximately \$41 million. In January 2009, we filed the depreciation study with the PSCW. If the PSCW approves the depreciation study, we would expect to implement the new depreciation rates in late 2009 or early 2010. We do not expect the new depreciation rates to have a material impact on earnings because we anticipate that the new depreciation rates will be considered when the PSCW sets our 2010 electric and gas prices.

See Factors Affecting Results, Liquidity and Capital Resources -- Rates and Regulatory Matters in Item 7 of our 2008 Annual Report on Form 10-K for additional information regarding our rates and other regulatory matters.

PART I -- FINANCIAL INFORMATION -- (Cont'd)**ELECTRIC TRANSMISSION AND ENERGY MARKETS**

MISO: In connection with its status as a FERC approved RTO, MISO developed bid-based energy markets, which were implemented on April 1, 2005. In January 2009, MISO commenced the Energy and Operating Reserves Markets, which includes the bid-based energy markets and a new ancillary services market. We previously self-provided both regulation reserves and contingency reserves. In the MISO ancillary services market, we buy/sell regulation and contingency reserves from/to the market. The MISO ancillary services market is expected to reduce overall ancillary services costs in the MISO footprint. The MISO ancillary services market is also expected to enable MISO to assume significant balancing area responsibilities such as frequency control and disturbance control.

In MISO, base transmission costs are currently being paid by LSEs located in the service territories of each MISO transmission owner. In February 2008, FERC issued several orders confirming that the current transmission cost allocation methodology is just and reasonable and should continue in the future. These orders are subject to appeals.

In April 2006, FERC issued an order determining that MISO had not applied its energy markets tariff correctly in the assessment of RSG charges. FERC ordered MISO to resettle all affected transactions retroactive to the commencement of the energy market. In October 2006 and March 2007, we received additional rulings from FERC on these issues. FERC's rulings have been challenged by MISO and numerous other market participants. MISO commenced with the resettlement of the market in accordance with the orders in July 2007. The resettlement was completed in January 2008 and resulted in a net cost increase of \$7.5 million to us. Several entities filed formal complaints with FERC on the assessment of these charges. We filed in support of these complaints.

In November 2007, FERC issued another RSG order related to the rehearing requests previously filed. This order provided a clarification that was contrary to how MISO implemented the last resettlement. Once again, we filed for rehearing and/or clarification with FERC, along with several other parties.

In addition, FERC ruled on the formal complaints filed by other entities in August 2007. FERC ruled that the current RSG cost allocation methodology may be unjust and unreasonable and established a refund effective date of August 10, 2007. MISO was ordered to file a new cost allocation methodology by March 2008. MISO filed new tariff language which indicated the new cost allocation methodology cannot be applied retroactively. We extended our previous rehearing/clarification request to include the timeframe from the established refund date through March 2008. In September 2008, FERC set a paper hearing for the formal complaints filed in 2007. FERC ruled on the outstanding rehearing/clarification requests and formal complaints in November 2008. FERC's ruling orders the resettlements to begin from the date the MISO Energy Markets commenced in order to correct the RSG cost allocation methodology. Additionally, the order also set a new RSG cost allocation effective August 10, 2007. However, numerous entities filed rehearing requests in objection of these rulings. Although MISO requested a postponement of the resettlements until the matter is resolved, the resettlement commenced in March 2009. This resettlement period is expected to conclude in January 2010. Based on our analysis of the FERC decision and MISO's proposed implementation of FERC's ruling, we estimate that there could be a refund to us of up to \$17 million. Due to the uncertainty around the ultimate outcome of the RSG cost allocation, we have not reflected the potential impact of this potential resettlement on our financial statements as of March 31, 2009.

Additionally, new arguments have been filed with FERC in relation to the Ancillary Services Market tariff language regarding the RSG cost allocation. In response, MISO has once again filed a new rate proposal related to the RSG cost allocation methodology that, if approved, is expected to be implemented in late 2009 or early 2010.

PART I -- FINANCIAL INFORMATION -- (Cont'd)

As part of MISO, a market-based platform was developed for valuing transmission congestion premised upon the LMP system that has been implemented in certain northeastern and mid-Atlantic states. The LMP system includes the ability to mitigate or eliminate congestion costs through 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, 2008 through May 31, 2009. The resulting ARR valuation and the secured FTRs should adequately mitigate our transmission congestion risk for that period.

ENVIRONMENTAL MATTERS

National Ambient Air Quality Standards: In 2000 and 2001, Michigan and Wisconsin finalized state rules implementing phased emission reductions required to meet the NAAQS for 1-hour ozone. In 2004, the EPA began implementing NAAQS for 8-hour ozone and PM_{2.5}. In December 2006, the EPA further revised the PM_{2.5} standard, and in March 2008, the EPA announced its decision to further lower the 8-hour ozone standard.

8-hour Ozone Standard: In April 2004, the EPA designated 10 counties in southeastern Wisconsin as non-attainment areas for the 8-hour ozone NAAQS. States were required to develop and submit SIPs to the EPA by June 2007 to demonstrate how they intended to comply with the 8-hour ozone NAAQS. Instead of submitting a SIP, Wisconsin submitted a request to redesignate all counties in southeastern Wisconsin to be in attainment with the standard. In addition to the request for redesignation, Wisconsin also adopted the RACT rule that applies to emissions from our power plants in the affected areas of Wisconsin. We believe compliance with the NO_x emission reduction requirements under the Consent Decree will substantially mitigate costs to comply with the RACT rule. In March 2008, the EPA issued a determination that the state of Wisconsin had failed to submit a SIP. We do not anticipate any further requirements to reduce emissions as a result of this finding, but we are unable to predict that outcome until Wisconsin responds to this finding (expected in July 2009) and the EPA subsequently takes a final approval action. In March 2008, the EPA announced its decision to further lower the 8-hour ozone standard. Although additional counties may be designated as non-attainment areas under the revised standard, until those designations become final and until any potential additional rules are adopted, we are unable to predict the impact on the operation of our existing coal-fired generation facilities.

PM_{2.5} Standard: In December 2004, the EPA designated PM_{2.5} non-attainment areas in the country. All counties in Wisconsin and all counties in the Upper Peninsula of Michigan were designated as in attainment with the standard. In December 2006, a more restrictive federal standard became effective; however, on February 24, 2009, the D.C. Circuit Court of Appeals issued a decision on the revised standard and remanded it back to the EPA for revision. The court's decision will likely result in an even more stringent annual PM_{2.5} standard. Until such time as the EPA revises the standard consistent with the court's decision and the states develop rules and submit SIPs to the EPA to demonstrate how they intend to comply with the standard, we are unable to predict the impact of this more restrictive standard on the operation of our existing coal-fired generation facilities or Wisconsin Energy's new PTF generating units that we are leasing, including OC 1, OC 2 and PWGS.

Clean Air Mercury Rule: The EPA issued the final CAMR in March 2005, following the agency's 2000 regulatory determination that utility mercury emissions should be regulated. CAMR would limit mercury emissions from new and existing coal-fired power plants and cap utility mercury emissions in two phases, applicable in 2010 and 2018. The caps would limit emissions at approximately 20% and ultimately 70% below current utility mercury levels.

PART I -- FINANCIAL INFORMATION -- (Cont'd)

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 re-consideration. The D.C. Circuit denied a request for a rehearing and the parties subsequently petitioned the U.S. Supreme Court for review of the D.C. Circuit's decision. In February 2009, the U.S. Supreme Court denied the petition for certiorari. In December 2008, a number of environmental groups also filed a complaint with the D.C. Circuit asking that the court place the EPA on a schedule for promulgating Maximum Achievable Control Technology limits for electric utilities. This latest complaint is still being processed by the D.C. Circuit.

Clean Air Visibility Rule: The EPA issued CAVR in June 2005 to address Regional Haze, or regionally-impaired visibility caused by multiple sources over a wide area. The rule defines BART requirements for electric generating units and how BART will be addressed in the 28 states subject to EPA's CAIR. Under CAVR, states are required to identify certain industrial facilities and power plants that affect visibility in the nation's 156 Class I protected areas. States are then required to determine the types of emission controls that those facilities must use to control their emissions. The pollutants from power plants that reduce visibility include particulate matter or compounds that contribute to fine particulate formation, NO_x, SO₂ and ammonia. States were required to submit SIPs to implement CAVR to the EPA by December 2007. Wisconsin has not yet submitted a SIP. Michigan submitted a SIP, which was partially approved. The reductions associated with the state plans are scheduled to begin to take effect in 2014, with full implementation before 2018. In response to a citizen suit, in January 2009, the EPA issued a finding of failure to 37 states, including Wisconsin and Michigan, regarding their failure to submit SIPs. The finding starts a two-year review window for the EPA to issue Federal Implementation Plans, unless a state submits and receives SIP approval. Failure to submit an approved SIP does not initiate any federal sanctions against the states.

Wisconsin and Michigan have completed the BART rules, which cover one aspect of CAVR regulations. Wisconsin BART rules became effective in July 2008 and Michigan BART rules became effective in September 2008.

Both Wisconsin and Michigan BART rules are based, in part, on utility reductions of NO_x and SO₂ that were expected to occur under CAIR. Therefore, we will not be able to determine final impacts of these rules until the EPA completes a new CAIR rule pursuant to a ruling by the U.S. Court of Appeals for the D.C. Circuit requiring it to do so.

Clean Water Act: Section 316(b) of the CWA requires that the location, design, construction and capacity of cooling water intake structures reflect BTA for minimizing adverse environmental impact. This law dates back to 1972; however, prior to September 2004, there were no federal rules that defined precisely how states and the EPA regions were to make BTA determinations for existing facilities. In September 2004, the EPA adopted its "Phase II rule" which established, for the first time, national performance standards and compliance alternatives for existing facilities that are designed to minimize the potential adverse environmental impacts to aquatic organisms associated with water withdrawals from cooling water intakes. Costs associated with implementation of the 316(b) rules for our Oak Creek Power Plant, We Power's Oak Creek expansion and PWGS were included in project costs.

In January 2007, the Federal Court of Appeals for the Second Circuit issued a decision concerning the Phase II rule for existing facilities (*Riverkeeper, Inc. v. EPA*, 475 F. 3d 83 (2d Cir. 2007)). The Second Circuit found certain portions of the rule impermissible, including portions that permitted approval of water intake system technologies based on a cost-benefit analysis, and remanded several parts of the Phase II rule to the EPA for further consideration or potential additional rulemaking. Subsequently, industry representatives sought the U.S. Supreme Court's review of the Second Circuit decision.

PART I -- FINANCIAL INFORMATION -- (Cont'd)

In April 2009, the Supreme Court issued its decision on the Phase II rule. As it relates to the cost-benefit analysis, the Supreme Court reversed the Second Circuit and held that it was permissible for the EPA to rely on cost-benefit analysis in setting national performance standards and in providing variances from those standards. The Supreme Court did not address other aspects of the Second Circuit decision. The Supreme Court remanded the case for further proceedings consistent with its opinion.

Until the EPA completes its reconsideration and rulemaking, we cannot predict what impact these changes may have on our facilities. The decision will not affect the new units at the Oak Creek expansion because those units were permitted based on a BTA decision under the Phase I rule for new facilities.

EPA Advance Notice of Proposed Rulemaking: In July 2008, the EPA issued an ANPR seeking comment on a large array of possible regulatory actions it is contemplating under the CAA to reduce greenhouse gas emissions. The proposed rules impact virtually all aspects of the economy including electric and natural gas utilities.

The EPA ANPR followed a U.S. Supreme Court decision in 2007 requiring the EPA to regulate greenhouse gas emissions from new motor vehicles under the CAA if it finds that they endanger public health or welfare. The ANPR sought comment on whether the EPA should make that finding and, if so, the types of regulations it should adopt. The comment period has closed, and in April 2009 the EPA issued for public comment its finding that greenhouse gas emissions endanger public health and welfare, and that new motor vehicles contribute to greenhouse gas emissions and the threat of climate change. The EPA states that the proposed action, if finalized, would not itself impose any requirements on industry or other entities. An endangerment finding is the first step in the process of regulating greenhouse gas emissions under the CAA.

A decision to regulate greenhouse gas emissions under one section of the CAA could lead to regulation of greenhouse gas emissions under other sections of the Act, including sections establishing permitting requirements for major stationary sources of air pollutants like electric generating plants. Although we cannot predict at this time what impact such a finding or any subsequent rulemaking will have on us, we would expect it to be negative.

See Factors Affecting Results, Liquidity and Capital Resources -- Environmental Matters in Item 7 of our 2008 Annual Report on Form 10-K for additional information regarding environmental matters affecting our operations.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

For information concerning market risk exposures at Wisconsin Electric Power Company, 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 2008 Annual Report on Form 10-K.

PART I -- FINANCIAL INFORMATION -- (Cont'd)**ITEM 4T. CONTROLS AND PROCEDURES**

Disclosure Controls and Procedures: Our management, with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of our disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the Exchange Act)) as of the end of the period covered by this report. Based upon such evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of such period, our disclosure controls and procedures are effective (i) in recording, processing, summarizing and reporting, on a timely basis, information required to be disclosed by us in the reports that we file or submit under the Exchange Act and (ii) to ensure that information required to be disclosed in the reports that we file or submit under the Exchange Act is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosure.

Internal Control Over Financial Reporting: There has not been any change in our internal control over financial reporting (as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) during the fiscal quarter to which this report relates that 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 2008 Annual Report on Form 10-K.

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

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 -- Rates and Regulatory Matters in Part I of this report for information concerning rate matters in the jurisdictions where we do business.

ITEM 1A. RISK FACTORS

See Item 1A. Risk Factors in our 2008 Annual Report on Form 10-K for a discussion of certain risk factors applicable to us.

PART II -- OTHER INFORMATION -- (Cont'd)

ITEM 6. EXHIBITS

Exhibit No.

31 Rule 13a-14(a) / 15d-14(a) Certifications

- 31.1 Certification Pursuant to Rule 13a-14(a) or 15d-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
- 31.2 Certification Pursuant to Rule 13a-14(a) or 15d-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32 Section 1350 Certifications

- 32.1 Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
- 32.2 Certification Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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 ELECTRIC POWER COMPANY

(Registrant)

/s/STEPHEN P. DICKSON

Date: May 7, 2009

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