WISCONSIN ENERGY CORP
Form 10-Q
August 04, 2009

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, DC 20549

FORM 10-Q

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

For the Quarterly Period Ended

June 30, 2009

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

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

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

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

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

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

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date (June 30, 2009):

Common Stock, $.01 Par Value, 116,911,980 shares outstanding.

WISCONSIN ENERGY CORPORATION

FORM 10-Q REPORT FOR THE QUARTER ENDED JUNE 30, 2008

TABLE OF CONTENTS

DEFINITION OF ABBREVIATIONS AND INDUSTRY TERMS

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

Wisconsin Energy Subsidiaries and Affiliates

Primary Subsidiaries	
Edison Sault	Edison Sault Electric Company

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

Significant Assets

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

Other Affiliates

ERS	Elm Road Services, LLC
Minergy	Minergy LLC
Wispark	Wispark LLC

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

Other Terms and Abbreviations

ARRs	Auction Revenue Rights

Bechtel	Bechtel Power Corporation
Compensation Committee	Compensation Committee of the Board of Directors
CPCN	Certificate of Public Convenience and Necessity

4

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 our 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.

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

- 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.

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

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

- 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 any of our subsidiaries; and our credit ratings.

- The investment performance of our 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 performance of projects undertaken by our non-utility businesses.

- The cyclical nature of property values that could affect our real estate investments.

- Changes to the legislative or regulatory restrictions or caps on non-utility acquisitions, investments or projects, including the State of Wisconsin's public utility holding company law.

- Other business or investment considerations that may be disclosed from time to time in our 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 Energy Corporation 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 Energy Corporation is a diversified holding company which conducts its operations primarily in two operating segments: a utility energy segment and a non-utility energy segment. Unless qualified by their context when used in this document, the terms Wisconsin Energy, the Company, our, us or we refer to the holding company and all of its subsidiaries. Our primary subsidiaries are Wisconsin Electric, Wisconsin Gas, We Power and Edison Sault.

Utility Energy Segment:

Our utility energy segment consists of: Wisconsin Electric, which serves electric customers in Wisconsin and the Upper Peninsula of Michigan, gas customers in Wisconsin and steam customers in metropolitan Milwaukee, Wisconsin; Wisconsin Gas, which serves gas customers in Wisconsin; and Edison Sault, which serves electric customers in the Upper Peninsula of Michigan. Wisconsin Electric and Wisconsin Gas operate under the trade name of "We Energies".

Non-Utility Energy Segment:

Our non-utility energy segment consists primarily of We Power. We Power was formed in 2001 to design, construct, own and lease to Wisconsin Electric the new generating capacity included in our PTF strategy. See Item 7 - Management's Discussion and Analysis of Financial Condition and Results of Operations in our 2008 Annual Report on Form 10-K for more information on PTF.

We have prepared the unaudited interim financial statements presented in this Form 10-Q pursuant to the rules and regulations of the SEC. We have condensed or omitted some information and note disclosures normally included in financial statements prepared in accordance with GAAP pursuant to these rules and regulations. This Form 10-Q, including the financial statements contained herein, should be read in conjunction with our 2008 Annual Report on Form 10-K, including the financial statements and notes therein.

PART I -- FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

WISCONSIN ENERGY CORPORATION
CONSOLIDATED CONDENSED INCOME STATEMENTS
(Unaudited)

	Three Months Ended June 30		Six Months Ended June 30	
	2009	2008	2009	2008
	(Millions of Dollars, Except Per Share Amounts)			
Operating Revenues	$842.5	$945.4	$2,238.7	$2,376.5
Operating Expenses				
Fuel and purchased power	253.6	298.1	520.0	636.3
Cost of gas sold	102.0	185.5	604.7	745.7
Other operation and maintenance	308.3	333.3	642.7	702.7
Depreciation, decommissioning and amortization	86.3	80.4	172.1	158.1
Property and revenue taxes	28.2	27.2	56.3	54.3
Total Operating Expenses	778.4	924.5	1,995.8	2,297.1
Amortization of Gain	55.1	87.0	119.3	246.0
Operating Income	119.2	107.9	362.2	325.4
Equity in Earnings of Transmission Affiliate	14.4	12.1	28.7	23.6
Other Income, net	7.3	7.9	13.6	18.5
Interest Expense, net	39.8	35.4	80.6	74.6
Income from Continuing Operations Before Income Taxes	101.1	92.5	323.9	292.9
Income Taxes	37.7	34.3	119.0	111.7
Income from Continuing Operations	63.4	58.2	204.9	181.2
Income (Loss) from Discontinued Operations, Net of Tax	0.3	(0.2)	0.3	-
Net Income	$63.7	$58.0	$205.2	$181.2
Earnings Per Share (Basic)				
Continuing operations	$0.54	$0.50	$1.75	$1.55
Discontinued operations	-	-	-	-
Total Earnings Per Share (Basic)	$0.54	$0.50	$1.75	$1.55

Earnings Per Share (Diluted)				
Continuing operations	$0.54	$0.49	$1.74	$1.53
Discontinued operations	-	-	-	-
Total Earnings Per Share (Diluted)	$0.54	$0.49	$1.74	$1.53
Weighted Average Common Shares Outstanding (Millions)				
Basic	116.9	116.9	116.9	116.9
Diluted	117.8	118.3	117.9	118.3
Dividends Per Share of Common Stock	$0.3375	$0.27	$0.6750	$0.54

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

8

WISCONSIN ENERGY CORPORATION

CONSOLIDATED CONDENSED BALANCE SHEETS

	(Unaudited) June 30, 2009	December 31, 2008
	(Millions of Dollars)	
Assets		
Property, Plant and Equipment		
In service	$ 10,167.7	$ 9,909.4
Accumulated depreciation	(3,409.5)	(3,312.9)
	6,758.2	6,596.5
Construction work in progress	1,920.2	1,829.9
Leased facilities, net	73.4	76.2
Net Property, Plant and Equipment	8,751.8	8,502.6
Investments		
Restricted cash	109.9	172.4
Equity investment in transmission affiliate	293.7	276.3

Other	38.7	41.6
Total Investments	442.3	490.3
Current Assets		
Cash and cash equivalents	12.5	32.5
Restricted cash	173.5	214.1
Accounts receivable	354.3	369.5
Accrued revenues	159.4	341.2
Materials, supplies and inventories	314.5	344.7
Regulatory assets	95.5	82.5
Prepayments and other	190.4	323.0
Total Current Assets	1,300.1	1,707.5
Deferred Charges and Other Assets		
Regulatory assets	1,204.0	1,261.1
Goodwill	441.9	441.9
Other	158.2	214.4
Total Deferred Charges and Other Assets	1,804.1	1,917.4
Total Assets	$ 12,298.3	$ 12,617.8
Capitalization and Liabilities		
Capitalization		
Common equity	$ 3,467.1	$ 3,336.9
Preferred stock of subsidiary	30.4	30.4
Long-term debt	3,820.1	4,074.7
Total Capitalization	7,317.6	7,442.0
Current Liabilities		
Long-term debt due currently	273.0	61.8
Short-term debt	780.2	602.3
Accounts payable	279.3	441.0
Regulatory liabilities	239.4	310.8
Other	249.1	319.2
Total Current Liabilities	1,821.0	1,735.1
Deferred Credits and Other Liabilities		
Regulatory liabilities	1,014.5	1,084.4
Deferred income taxes - long-term	839.7	814.0
Deferred revenue, net	639.0	545.4
Pension and other benefit obligations	317.6	635.0
Other	348.9	361.9
Total Deferred Credits and Other	3,159.7	3,440.7

Liabilities		
Total Capitalization and Liabilities	$ 12,298.3	$ 12,617.8

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

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

		Six Months Ended June 30	
		2009	2008
		(Millions of Dollars)	
Operating Activities			
Net income		$ 205.2	$ 181.2
Reconciliation to cash			
Depreciation, decommissioning and amortization		175.5	164.4
Amortization of gain		(119.3)	(246.0)
Equity in earnings of transmission affiliate		(28.7)	(23.6)
Distributions from transmission affiliate		22.8	18.4
Deferred income taxes and investment tax credits, net		14.6	123.8
Deferred revenue		97.5	102.0
Contributions to benefit plans		(289.3)	(48.4)
Change in -	Accounts receivable and accrued revenues	168.3	106.5
	Inventories	30.2	82.3
	Other current assets	18.0	15.5
	Accounts payable	(156.9)	(47.2)
	Accrued income taxes, net	99.5	(15.9)
	Deferred costs, net	23.1	56.6
	Other current liabilities	(11.4)	23.0
Other, net		(16.7)	81.1

Cash Provided by Operating Activities	232.4	573.7
Investing Activities		
Capital expenditures	(365.1)	(642.0)
Investment in transmission affiliate	(11.5)	(9.4)
Proceeds from asset sales, net	14.8	9.5
Change in restricted cash	103.1	154.1
Other, net	(47.6)	(46.6)
Cash Used in Investing Activities	(306.3)	(534.4)
Financing Activities		
Exercise of stock options	6.3	7.6
Purchase of common stock	(10.5)	(14.9)
Dividends paid on common stock	(78.9)	(63.1)
Issuance of long-term debt	11.5	156.0
Retirement and repurchase of long-term debt	(53.3)	(174.3)
Change in short-term debt	177.9	48.7
Other, net	0.9	(0.1)
Cash Provided by (Used in) Financing Activities	53.9	(40.1)
Change in Cash and Cash Equivalents	(20.0)	(0.8)
Cash and Cash Equivalents at Beginning of Period	32.5	27.4
Cash and Cash Equivalents at End of Period	$ 12.5	$ 26.6

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

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 and six months ended June 30, 2009 are not necessarily indicative of the results which may be expected for the entire fiscal year 2009 because of seasonal and other factors.

Reclassifications:

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

The reclassifications relate to the reporting of discontinued operations. The footnotes contained herein reflect continuing operations for all periods presented. For further information, see Note 5.

Subsequent Events:

We have evaluated and determined that no material events took place after our balance sheet date of June 30, 2009 through our financial statement issuance date of August 4, 2009.

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 adopted the provisions of FSP SFAS 157-2 effective January 1, 2009 and the provisions of FSP SFAS 157-4 effective April 1, 2009. The adoption of SFAS 157 did not have a significant financial impact on our financial condition, results of operations or cash flow. See Note 6 -- 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 a material financial impact on our financial condition, results of operations or cash flows.

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 financial condition, results of operations or cash flows. See Note 7 -- Derivative Instruments for required disclosures.

Subsequent Events:

In May 2009, the FASB issued SFAS 165. SFAS 165 provides guidance on management's assessment of subsequent events. This statement clarifies that management must evaluate, as of each reporting period, events or transactions that occur after the balance sheet date through the date the financial statements are issued or are available to be issued. SFAS 165 is effective for interim and annual periods ending after June 15, 2009. We adopted the provisions of SFAS 165 effective June 30, 2009. The adoption of SFAS 165 had no material financial impact on our financial condition, results of operations or cash flows.

Interim Disclosures about Fair Value of Financial Instruments:

In April 2009, the FASB issued FSP SFAS 107-1, which requires disclosures about the fair value of financial instruments for interim reporting periods of publicly traded companies as well as in financial statements. We adopted the provisions of FSP SFAS 107-1 effective June 30, 2009. The adoption of FSP SFAS 107-1 had no financial impact on our financial condition, results of operations or cash flows.

Recognition and Presentation of Other-Than-Temporary Impairments:

In April 2009, the FASB issued FSP SFAS 115-2, which amends the other-than-temporary impairment guidance for debt securities to be more operational and to improve the presentation and disclosure of the other-than-temporary impairments on debt and equity securities in financial statements. We adopted FSP SFAS 115-2 effective June 30, 2009. The adoption of FSP SFAS 115-2 had no material financial impact on our financial condition, results of operations or cash flows.

Amendments to Variable Interest Entity Consolidation Guidance:

In June 2009, the FASB issued SFAS 167, which amends certain requirements of FIN 46(R). The purpose of this standard is to improve financial reporting by enterprises with variable interest entities. SFAS 167 is effective for all new and existing variable interest entities for fiscal years beginning after November 15, 2009. We expect to adopt SFAS 167 on January 1, 2010.

Employers' Disclosures about Post-retirement Benefit Plan Assets

: In December 2008, the FASB issued FSP SFAS 132(R)-1, which provides guidance on an employer's disclosures about plan assets of a defined benefit pension or other post-retirement plan. FSP SFAS 132(R)-1 will result in expanded disclosures related to post-retirement benefit plan assets and is effective for fiscal years ending after December 15, 2009. We expect to adopt FSP SFAS 132(R)-1 on December 31, 2009.

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

Background:

As part of our PTF strategy, our non-utility subsidiary, We Power, is building four new generating units (PWGS 1 and 2 and OC 1 and 2) that will be leased to our utility subsidiary, Wisconsin Electric, under long-term leases that have been approved by the PSCW, our primary regulator. The leases are designed to recover the capital costs of the plant including a return. PWGS 1 was placed in service in July 2005 and PWGS 2 was placed in service in May 2008. The accompanying consolidated financial statements eliminate all intercompany transactions between We Power and Wisconsin Electric and reflect the cash inflows from Wisconsin Electric customers and the cash outflows to our vendors and suppliers.

The Oak Creek expansion includes common projects that will benefit the existing units at this site as well as the new units. These projects include a coal handling facility and a water intake system. The costs associated with these projects are included in the OC 1 captions below. In November 2007, the coal handling system for Oak Creek was placed in service, and the water intake system was placed in service in January 2009.

During Construction:

Under the terms of each lease, we collect in current rates amounts representing our pre-tax cost of capital (debt and equity) associated with capital expenditures for our PTF units. Our

pre-tax cost of capital is approximately 14%. The carrying costs that we collect in rates are recorded as deferred revenue and will be amortized to revenue over the term of each lease once the respective unit is placed into service. During the construction of our PTF units, we capitalize interest costs at an overall weighted-average pre-tax cost of interest which was approximately 5% for the six months ended June 30, 2009 and approximately 6% in 2008. Capitalized interest is included in the total cost of the PTF units shown below.

Cash Flows:

The following table identifies key pre-tax cash outflows and inflows for the six months ended June 30 related to the construction of our PTF units as compared to Wisconsin Energy overall:

	Capital Expenditures (Millions of Dollars)				Total	
	PWGS 1	PWGS 2	OC 1	OC 2	PTF	WEC
2009	$ -	$ -	$45.2	$35.3	$80.5	$365.1
2008	$ -	$42.0	$157.1	$141.6	$340.7	$642.0

	Capitalized Interest (Millions of Dollars)				Total	
	PWGS 1	PWGS 2	OC 1	OC 2	PTF	WEC
2009	$ -	$ -	$22.0	$13.4	$35.4	$38.2
2008	$ -	$7.1	$23.1	$11.1	$41.3	$43.3

	Deferred Revenue (Millions of Dollars)				Total	
	PWGS 1	PWGS 2	OC 1	OC 2	PTF	WEC
2009	$ -	$ -	$60.5	$37.0	$97.5	$97.5
2008	$ -	$16.9	$57.2	$27.9	$102.0	$102.0

Balance Sheet: As noted above, we collect in current rates carrying costs that are calculated based on the cash expenditures included in CWIP multiplied by our pre-tax cost of capital. The carrying costs are recorded as deferred revenue and included in Other long-term liabilities. Our total CWIP balance includes cash expenditures, capitalized interest and accruals. The following table identifies key amounts related to our PTF units that were recorded on our balance sheet as of June 30, 2009 and December 31, 2008:

	CWIP - Cash Expenditures (Millions of Dollars)				Total
	PWGS 1	PWGS 2	OC 1	OC 2	PTF
June 30, 2009	$ -	$ -	$892.0	$554.2	$1,446.2
December 31, 2008	$ -	$ -	$952.9	$520.8	$1,473.7

	Total CWIP (Millions of Dollars)				Total	
	PWGS 1	PWGS 2	OC 1	OC 2	PTF	WEC
June 30, 2009	$ -	$ -	$1,009.8	$618.1	$1,627.9	$1,920.2
December 31, 2008	$ -	$ -	$1,065.5	$571.3	$1,636.8	$1,829.9

	Net Plant in Service (Millions of Dollars)				Total	
	PWGS 1	PWGS 2	OC 1	OC 2	PTF	WEC
June 30, 2009	$328.6	$356.6	$322.7	$ -	$1,007.9	$6,758.2
December 31, 2008	$332.7	$360.3	$194.0	$ -	$887.0	$6,596.5

	Deferred Revenue (Millions of Dollars)				Total	
	PWGS 1	PWGS 2	OC 1	OC 2	PTF	WEC
June 30, 2009	$61.1	$75.7	$345.3	$156.9	$639.0	$639.0
December 31, 2008	$62.7	$77.3	$285.5	$119.9	$545.4	$545.4

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

We recognize revenues related to the lease payments that are included in our rates. In addition, our revenues include the amortization of the deferred revenues that reflect the carrying costs that are collected during construction. The deferred revenue is amortized on a straight line basis over the lease term. We depreciate the units on a straight line basis over their expected service life.

In July 2005, PWGS 1 was placed in service. This asset had a cost of approximately $364.3 million, which included approximately $31.1 million of capitalized interest. The asset is being depreciated over its estimated useful life of 37 years. The cost of the plant, plus a return on the investment, is expected to be recovered through Wisconsin Electric's rates over a 25 year period at an annual amount of approximately $48 million.

In November 2007, the coal handling system for Oak Creek was placed into service. This asset had a cost of approximately $199.1 million. This asset is being depreciated over its estimated useful life of 40 years. The cost of the system, plus a return on the investment, is expected to be recovered through Wisconsin Electric's rates over a 32 year period at an annual amount of approximately $24 million.

In May 2008, PWGS 2 was placed in service. This asset had a cost of approximately $366.0 million, which included approximately $34.0 million of capitalized interest. The asset is being depreciated over its estimated useful life of 37 years. The cost of the plant, plus a return on the investment, is expected to be recovered through Wisconsin Electric's rates over a 25 year period at an annual amount of approximately $49 million.

In January 2009, the new water intake system that serves both the existing units at Oak Creek and OC 1 and OC 2 was placed in service. This asset had a cost of approximately $132.5 million. This asset is being depreciated over its estimated useful life of 40 years. The cost of the system, plus a return on the investment, is expected to be recovered through Wisconsin Electric's rates over a 31 year period at an annual amount of approximately $16 million.

4 -- COMMON EQUITY

Share-Based Compensation Expense:

For a description of share-based compensation, including stock options, restricted stock and performance units, see Note J -- Common Equity in our 2008 Annual Report on Form 10-K. We utilize the straight-line attribution method for recognizing share-based compensation expense. Accordingly, for employee awards, equity classified share-based compensation cost is measured at the grant date based on the fair value of the award, and is recognized as expense over the requisite service period. There were no modifications to outstanding stock options during the period. Shares purchased on the open market by our independent agents are currently used to satisfy share-based awards.

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

	Three Months Ended June 30		Six Months Ended June 30	
	2009	2008	2009	2008
	(Millions of Dollars)			
Stock options	$2.8	$2.9	$5.3	$5.9

Performance units	0.1	1.7	3.9	2.9
Restricted stock	0.3	0.3	0.5	0.6
Share-based compensation expense	$3.2	$4.9	$9.7	$9.4
Related Tax Benefit	$1.3	$2.0	$3.9	$3.8

Stock Option Activity:

During the first six months of 2009, the Compensation Committee granted 1,216,625 options that had an estimated fair value of $8.01 per share. During the first six months of 2008, the Compensation Committee granted 1,362,160 options that had an estimated fair value of $9.39 per share. The following assumptions were used to value the options using a binomial option pricing model:

	2009	2008
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 our historical experience.

The following is a summary of our stock option activity for the three and six months ended June 30, 2009:

Stock Options	Number of Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (Millions)
Outstanding as of April 1, 2009	9,633,669	$37.81		
Granted	-	$ -		
Exercised	(119,858)	$27.27		
Forfeited	(7,360)	$46.09		
Outstanding as of June 30, 2009	9,506,451	$37.93		
Outstanding as of January 1, 2009	8,543,564	$36.97		
Granted	1,216,625	$42.22		

Exercised	(246,378)	$25.41		
Forfeited	(7,360)	$46.09		
Outstanding as of June 30, 2009	9,506,451	$37.93	6.3	$47.8
Exercisable as of June 30, 2009	5,789,956	$32.74	4.8	$47.8

The intrinsic value of options exercised was $1.4 million and $3.9 million for the three and six months ended June 30, 2009, and $4.1 million and $6.2 million for the same periods in 2008, respectively. Cash received from options exercised was $6.3 million and $7.6 million for the six months ended

15

June 30, 2009 and 2008, respectively. The actual tax benefit realized for the tax deductions from option exercises for the same periods was approximately $1.6 million and $1.9 million, respectively.

Stock options to purchase 3,945,255 shares of common stock, with prices ranging from $42.22 to $48.04 per share, respectively, were outstanding during the first six months of 2009, but were not included in the computation of diluted earnings per share because they were anti-dilutive.

The following table summarizes information about stock options outstanding as of June 30, 2009:

	Options Outstanding			Options Exercisable		
		Weighted-Average			Weighted-Average	
Range of Exercise Prices	Number of Options	Exercise Price	Remaining Contractual Life (Years)	Number of Options	Exercise Price	Remaining Contractual Life (Years)
$19.62 to $31.07	1,878,911	$25.17	3.2	1,878,911	$25.17	3.2
$33.44 to $39.48	3,682,285	$35.67	5.5	3,682,285	$35.67	5.5
$42.22 to $48.04	3,945,255	$46.13	8.5	228,760	$47.79	7.6
	9,506,451	$37.93	6.3	5,789,956	$32.74	4.8

The following table summarizes information about our non-vested options during the three and six months ended June 30, 2009:

Non-Vested Stock Options	Number of Options	Weighted-Average Fair Value
Non-vested as of April 1, 2009	3,723,855	$8.72

Granted	-	$ -
Vested	-	$ -
Forfeited	(7,360)	$8.73
Non-vested as of June 30, 2009	3,716,495	$8.72
Non-vested as of January 1, 2009	3,598,379	$8.81
Granted	1,216,625	$8.01
Vested	(1,091,149)	$7.55
Forfeited	(7,360)	$8.73
Non-vested as of June 30, 2009	3,716,495	$8.72

As of June 30, 2009, total compensation costs related to non-vested stock options not yet recognized was approximately $13.0 million, which is expected to be recognized over the next 19 months on a weighted-average basis.

Restricted Shares:

The Compensation Committee has also approved restricted stock grants to certain key employees and directors. The following restricted stock activity occurred during the three and six months ended June 30, 2009:

Restricted Shares	Number of Shares	Weighted-Average Grant Date Fair Value
Outstanding as of April 1, 2009	117,510	
Granted	-	
Released / Forfeited	(4,780)	$27.76
Outstanding as of June 30, 2009	112,730	
Outstanding as of January 1, 2009	116,373	
Granted	14,216	$42.11
Released / Forfeited	(17,859)	$35.96
Outstanding as of June 30, 2009	112,730	

We record the market value of the restricted stock awards on the date of grant, and then we charge their value to expense over the vesting period of the awards. We also adjust expense for acceleration of vesting due to achievement of performance goals. The intrinsic value of restricted stock vesting was $0.1 million and $0.7 million for the three and six months ended June 30, 2009, and $0.8 million and $1.8 million for the same periods in 2008. The actual tax benefits realized for the tax deductions from released restricted shares was $0.1 million and $0.3 million for the three and six months ended June 30, 2009, and $0.3 million and $0.4 million for the same periods in 2008, respectively.

As of June 30, 2009, total compensation cost related to restricted stock not yet recognized was approximately $1.8 million, which is expected to be recognized over the next 32 months on a weighted-average basis.

Performance Units:

In January 2009 and 2008, the Compensation Committee granted 333,220 and 133,855 performance units, respectively, to officers and other key employees under the Wisconsin Energy Performance Unit Plan. Under the grants, the ultimate number of units that will be awarded is dependent upon the achievement of certain financial performance of our stock over a three year period. We are accruing compensation costs over the three year period based on our estimate of the final expected value of the awards. Performance units earned as of December 31, 2008 and 2007 vested and were settled during the first quarter of 2009 and 2008, and had a total intrinsic value of $8.4 million and $5.2 million, respectively. The actual tax benefit realized for the tax deductions from the settlement of performance units was approximately $3.1 million and $1.8 million, respectively. As of June 30, 2009, total compensation cost related to performance units not yet recognized was approximately $15.4 million, which is expected to be recognized over the next 26 months on a weighted-average basis.

Restrictions:

Wisconsin Energy's ability as a holding company to pay common dividends primarily depends on the availability of funds received from its principal utility subsidiaries, Wisconsin Electric and Wisconsin Gas. Various financing arrangements and regulatory requirements impose certain restrictions on the ability of our principal utility subsidiaries to transfer funds to us in the form of cash dividends, loans or advances. In addition, under Wisconsin law, Wisconsin Electric and Wisconsin Gas are prohibited from loaning funds, either directly or indirectly, to Wisconsin Energy. See Note J --Common Equity in our 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 dividend payments in the foreseeable future.

17

Comprehensive Income:

Comprehensive income includes all changes in equity during a period except those resulting from investments by and distributions to owners. We recorded the following total comprehensive income, net of tax, during the six months ended June 30:

Comprehensive Income	2009	2008
	(Millions of Dollars)	

Net Income	$205.2	$181.2
Other Comprehensive Income		
Hedging	0.2	0.2
Total Other Comprehensive Income	0.2	0.2
Total Comprehensive Income	$205.4	$181.4

5 -- DISCONTINUED OPERATIONS

Effective April 30, 2009, we sold our water utility to the City of Mequon, Wisconsin for approximately $14.5 million.

The assets and liabilities associated with our water utility reclassified as held for sale within other current assets and liabilities on our Consolidated Condensed Balance Sheets as of December 31, 2008 were $14.4 million and $0.3 million, respectively. We also reclassified the water utility income as discontinued operations in the accompanying Consolidated Condensed Income Statements.

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

	Three Months Ended June 30		Six Months Ended June 30	
	2009 (a)	2008	2009 (a)	2008
	(Millions of Dollars)			
Operating revenues	$0.4	$0.7	$1.1	$1.4
Operating expenses	0.1	0.4	0.4	0.7
Income before income taxes	0.3	0.3	0.7	0.7
Income tax expense	0.1	0.2	0.3	0.3
Income from discontinued water operations, net of tax	0.2	0.1	0.4	0.4
Income (Loss) from discontinued other operations, net of tax	0.1	(0.3)	(0.1)	(0.4)
Total Income (Loss) from Discontinued Operations, Net of Tax	$0.3	($0.2)	$0.3	$ -

(a) As a result of its sale effective April 30, 2009, we operated the water utility for one of the three months ended June 30, 2009 and for four of the six months ended June 30, 2009.

Cash provided by operating activities in our Consolidated Condensed Statements of Cash Flows reflects income from discontinued water operations, net of tax, of $0.4 million for the six months ended June 30, 2009 and 2008. Cash used in investing activities reflects activity from discontinued water operations of $0.1 million and $0.2 million for the six months ended June 30, 2009 and 2008, respectively. Discontinued water operations had no impact on financing activities for the six months ended June 30, 2009 and 2008.

6 -- FAIR VALUE MEASUREMENTS

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

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

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

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

Recurring Fair Value Measures	As of June 30, 2009			
	Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Assets:				
Restricted Cash	$283.4	$ -	$ -	$283.4
Derivatives	0.1	2.4	15.5	18.0
Total	$283.5	$2.4	$15.5	$301.4
Liabilities:				
Derivatives	$26.2	$6.3	$ -	$32.5
Total	$26.2	$6.3	$ -	$32.5

Recurring Fair Value Measures	As of December 31, 2008			
	Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Assets:				
Cash Equivalents	$9.1	$ -	$ -	$9.1
Restricted Cash	386.5	-	-	386.5
Derivatives	-	4.2	8.8	13.0
Total	$395.6	$4.2	$8.8	$408.6
Liabilities:				
Derivatives	$38.9	$32.1	$ -	$71.0
Total	$38.9	$32.1	$ -	$71.0

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.

The following tables summarize the fair value of derivatives classified as Level 3 in the fair value hierarchy:

Quarter to Date	2009	2008
	(Millions of Dollars)	
Balance as of April 1	$2.9	$4.5
Realized and unrealized gains (losses)	-	-
Purchases, issuances and settlements	12.6	17.0
Transfers in and/or out of Level 3	-	-
Balance as of June 30	$15.5	$21.5
Change in unrealized gains (losses) relating to instruments still held as of June 30	$ -	$ -

Year to Date	2009	2008
	(Millions of Dollars)	
Balance as of January 1	$8.8	$13.0
Realized and unrealized gains (losses)	-	-
Purchases, issuances and settlements	6.7	8.5
Transfers in and/or out of Level 3	-	-
Balance as of June 30	$15.5	$21.5
Change in unrealized gains (losses) relating to instruments still held as of June 30	$ -	$ -

Derivative instruments reflected in Level 3 of the hierarchy include MISO FTRs that are measured at fair value each reporting period using monthly or annual auction shadow prices from relevant auctions. Changes in fair value for Level 3 recurring items are recorded on our balance sheet. See Note 7 -- Derivative Instruments, for further information on the offset to regulatory assets and liabilities.

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

	June 30, 2009		December 31, 2008	
Financial Instruments	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(Millions of Dollars)			
Preferred stock, no redemption required	$30.4	$19.3	$30.4	$19.0
Long-term debt including current portion	$3,967.5	$3,889.8	$4,009.4	$3,711.9

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

7 -- DERIVATIVE INSTRUMENTS

We record derivative instruments on the balance sheet as an asset or liability measured at its fair value, and changes in the derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are met. For most energy related physical and financial contracts in our regulated operations that qualify as derivatives, the PSCW allows the effects of the fair market value accounting to be offset to regulatory assets and liabilities. We do not offset fair value amounts recognized for the right

to reclaim cash collateral or the obligation to return cash collateral against fair value amounts recognized for derivatives executed with the same counterparty under the same master netting arrangement. As of June 30, 2009, we recognized $50.0 million in regulatory assets and $17.9 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 and shareholders. Our approach is non-speculative and designed to mitigate risk and protect against price volatility. Regulated hedging programs require prior approval by the PSCW.

We record our current derivative assets on the balance sheet in Other current assets and the current portion of the liabilities in Other current liabilities. The long-term portion of our derivative assets of $0.2 million is recorded in Other deferred charges and other assets and the long-term portion of our derivative liabilities of $4.3 million is recorded in Other deferred credits and other liabilities. Our Consolidated Condensed Balance Sheet as of June 30, 2009 includes:

	Derivative Asset	Derivative Liability
	(Millions of Dollars)	
Natural Gas	$ -	$32.5
Fuel Oil	0.1	-
FTRs	15.5	-
Coal	2.4	-
Total	$18.0	$32.5

Our Consolidated Condensed Income Statements include gains (losses) on derivative instruments used in our risk management strategies under Fuel and purchased power for those commodities supporting our electric operations and under Cost of gas sold for the natural gas sold to our customers. Our estimated notional volumes and gain (losses) for the three and six months ended June 30, 2009 follow:

	Three Months Ended June 30, 2009		Six Months Ended June 30, 2009	
	Volume	Gains (Losses)	Volume	Gains (Losses)
		(Millions of Dollars)		(Millions of Dollars)
Natural Gas	23.3 million Dth	($28.7)	45.7 million Dth	($53.6)
Energy		(0.1)		(0.6)

	3,200 MWh purchased		15,120 MWh purchased	
Fuel Oil	1.7 million gallons	(0.9)	3.0 million gallons	(1.8)
FTRs	6,809 MW	4.1	14,772 MW	5.2
Total		($25.6)		($50.8)

The aggregate fair value of all derivative instruments that are in a liability position as of June 30, 2009 is $32.5 million, for which we have posted collateral of $36.5 million in the normal course of business.

8 -- BENEFITS

The components of our net periodic pension and OPEB costs for the three and six months ended June 30, 2009 and 2008 were as follows:

	Pension Benefits		OPEB	
Benefit Plan Cost Components	2009	2008	2009	2008
	(Millions of Dollars)			
Three Months Ended June 30				
Net Periodic Benefit Cost				
Service cost	$6.4	$4.0	$2.0	$2.5
Interest cost	17.9	18.2	5.0	4.8
Expected return on plan assets	(24.0)	(21.0)	(3.3)	(4.4)
Amortization of:				
Transition obligation	-	-	-	0.1
Prior service cost (credit)	0.5	0.7	(3.1)	(3.2)
Actuarial loss	4.2	4.5	2.2	1.2
Net Periodic Benefit Cost	$5.0	$6.4	$2.8	$1.0
Six Months Ended June 30				
Net Periodic Benefit Cost				
Service cost	$11.7	$8.7	$4.3	$5.2
Interest cost	36.1	35.5	10.3	10.0
Expected return on plan assets	(47.7)	(42.4)	(6.8)	(8.8)
Amortization of:				
Transition obligation	-	-	0.1	0.2

Prior service cost (credit)	1.1	1.3	(6.3)	(6.3)
Actuarial loss	9.4	8.2	4.5	2.9
Net Periodic Benefit Cost	$10.6	$11.3	$6.1	$3.2

In January 2009, we contributed $289.3 million to our 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 June 30, 2009, the Pension Trust held approximately $89 million of commercial paper issued by Wisconsin Energy.

9 -- GUARANTEES

We enter into various guarantees to provide financial and performance assurance to third parties on behalf of our affiliates. As of June 30, 2009, we had the following guarantees:

	Maximum Potential Future Payments	Outstanding	Liability Recorded
		(Millions of Dollars)	
Wisconsin Energy			
Non-Utility Energy	$ -	$ -	$ -
Other	0.2	0.2	-
Wisconsin Electric	2.9	0.1	-
Total	$3.1	$0.3	$ -

A non-utility energy segment guarantee in support of Wisvest-Connecticut, which we sold in December 2002 to PSEG, provides financial assurance for potential obligations relating to environmental

remediation under the original purchase agreement for Wisvest-Connecticut with The United Illuminating Company. The potential obligations for environmental remediation, which are unlimited, are reimbursable by PSEG under the terms of the sale agreement in the event that we are required to perform under the guarantee.

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

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

Postemployment Benefits:

Postemployment benefits provided to former or inactive employees are recognized when an event occurs. The estimated liability for such benefits was $17.4 million as of June 30, 2009 and $18.6 million as of December 31, 2008.

10 -- SEGMENT INFORMATION

Summarized financial information concerning our reportable operating segments for the three and six months ended June 30, 2009 and 2008 is shown in the following table:

	Reportable Operating Segments Energy		Corporate & Other (a) & Reconciling	Total
Wisconsin Energy Corporation	Utility	Non-Utility	Items	Consolidated
	(Millions of Dollars)			
Three Months Ended				
June 30, 2009				
Operating Revenues (b)	$839.9	$44.1	($41.5)	$842.5
Depreciation, Decommissioning and Amortization	$78.8	$7.3	$0.2	$86.3
Operating Income (Loss)	$90.2	$30.8	($1.8)	$119.2
Equity in Earnings of Unconsolidated Affiliates	$14.4	$ -	$ -	$14.4
Interest Expense, net	$29.5	$4.1	$6.2	$39.8
Income Tax Expense (Benefit)	$31.4	$11.1	($4.8)	$37.7
Income from Discontinued Operations, Net of Tax	$0.2	$ -	$0.1	$0.3
Net Income (Loss)	$50.4	$16.6	($3.3)	$63.7
Capital Expenditures	$144.7	$43.5	$5.5	$193.7
Three Months Ended				
June 30, 2008				
Operating Revenues (b)	$943.5	$32.0	($30.1)	$945.4
Depreciation, Decommissioning and Amortization	$75.2	$5.0	$0.2	$80.4
Operating Income (Loss)	$90.2	$20.0	($2.3)	$107.9
Equity in Earnings of Unconsolidated Affiliates	$12.1	$ -	($0.6)	$11.5
Interest Expense, net	$24.4	$1.9	$9.1	$35.4
Income Tax Expense (Benefit)	$30.7	$8.0	($4.4)	$34.3
Loss from Discontinued Operations, Net of Tax	$ -	$ -	($0.2)	($0.2)
Net Income (Loss)	$52.3	$11.9	($6.2)	$58.0
Capital Expenditures	$126.8	$166.8	$0.2	$293.8

Wisconsin Energy Corporation	Reportable Operating Segments Energy Utility	Non-Utility	Corporate & Other (a) & Reconciling Items	Total Consolidated
	(Millions of Dollars)			
Six Months Ended				
June 30, 2009				
Operating Revenues (b)	$2,235.5	$80.8	($77.6)	$2,238.7
Depreciation, Decommissioning and Amortization	$157.3	$14.5	$0.3	$172.1
Operating Income (Loss)	$306.5	$58.7	($3.0)	$362.2
Equity in Earnings of Unconsolidated Affiliates	$28.7	$ -	$ -	$28.7
Interest Expense, net	$59.6	$8.2	$12.8	$80.6
Income Tax Expense (Benefit)	$104.8	$21.9	($7.7)	$119.0
Income (Loss) from Discontinued Operations, Net of Tax	$0.4	$ -	($0.1)	$0.3
Net Income (Loss)	$183.8	$30.5	($9.1)	$205.2
Capital Expenditures	$274.9	$84.7	$5.5	$365.1
Total Assets (c)	$10,572.6	$2,613.8	($888.1)	$12,298.3
Six Months Ended				
June 30, 2008				
Operating Revenues (b)	$2,376.0	$51.7	($51.2)	$2,376.5
Depreciation, Decommissioning and Amortization	$148.7	$9.0	$0.4	$158.1
Operating Income (Loss)	$296.4	$34.2	($5.2)	$325.4
Equity in Earnings of Unconsolidated Affiliates	$23.6	$ -	($0.7)	$22.9
Interest Expense, net	$52.7	$3.7	$18.2	$74.6
Income Tax Expense (Benefit)	$108.0	$13.0	($9.3)	$111.7
	$0.4	$ -	($0.4)	$ -

Income (Loss) from Discontinued Operations, Net of Tax				
Net Income (Loss)	$173.8	$19.3	($11.9)	$181.2
Capital Expenditures	$299.8	$342.0	$0.2	$642.0
Total Assets (c)	$10,201.3	$2,345.6	($821.9)	$11,725.0

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

(b) An elimination for intersegment revenues of $41.6 million and $30.5 million for the three months ended June 30, 2009 and 2008, respectively, and $77.8 million and $50.4 million for the six months ended June 30, 2009 and 2008, respectively, is included in Operating Revenues.

(c) An elimination of $892.4 million and $786.3 million is included in Total Assets at June 30, 2009 and 2008, respectively, for all PTF-related activity between We Power and Wisconsin Electric.

11 -- VARIABLE INTEREST ENTITIES

The primary beneficiary of a variable interest entity must consolidate the related assets and liabilities. Certain disclosures are required by sponsors, significant interest holders in variable interest entities and potential variable interest entities.

We assess our relationships with potential variable interest entities such as our coal suppliers, natural gas suppliers, coal and gas transporters, and other counterparties in power purchase agreements and joint ventures. In making this assessment, we consider the potential that our contracts or other arrangements provide subordinated financial support, the potential for us to absorb losses or rights to residual returns of the entity, the ability to directly or indirectly make decisions about the entities' activities and other factors.

We have identified two tolling and purchased power agreements with third parties but have been unable to determine if we are the primary beneficiary of these two variable interest entities. 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 $446.2 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 June 30, 2009 and December 31, 2008, were $30.1 million and $66.4 million, respectively.

12 -- COMMITMENTS AND CONTINGENCIES

Environmental Matters:

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

Divestitures:

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

13 -- SUPPLEMENTAL CASH FLOW INFORMATION

During the six months ended June 30, 2009, we paid $79.8 million in interest, net of amounts capitalized, and $1.3 million in income taxes, net of refunds. During the six months ended June 30, 2008, we paid $90.7 million in interest, net of amounts capitalized, and $0.9 million in income taxes, net of refunds.

As of June 30, 2009 and 2008, the amount of accounts payable related to capital expenditures was $40.2 million and $45.0 million, respectively.

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

RESULTS OF OPERATIONS -- THREE MONTHS ENDED JUNE 30, 2009

CONSOLIDATED EARNINGS

The following table compares our operating income by business segment and our net income during the second quarter of 2009 with the second quarter of 2008 including favorable (better (B)) or unfavorable (worse (W)) variances:

	Three Months Ended June 30		
	2009	B (W)	2008
	(Millions of Dollars)		

Utility Energy Segment	$90.2	$ -	$90.2
Non-Utility Energy Segment	30.8	10.8	20.0
Corporate and Other	(1.8)	0.5	(2.3)
Total Operating Income	119.2	11.3	107.9
Equity in Earnings of Transmission Affiliate	14.4	2.3	12.1
Other Income, net	7.3	(0.6)	7.9
Interest Expense, net	39.8	(4.4)	35.4
Income from Continuing Operations Before Income Taxes	101.1	8.6	92.5
Income Taxes	37.7	(3.4)	34.3
Income from Continuing Operations	63.4	5.2	58.2
Income (Loss) from Discontinued Operations, Net of Tax	0.3	0.5	(0.2)
Net Income	$63.7	$5.7	$58.0
Diluted Earnings Per Share	$0.54	$0.05	$0.49

UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

Our utility energy segment contributed $90.2 million of operating income during the second quarter of 2009 and 2008. The following table summarizes the operating income of this segment between the comparative quarters:

	Three Months Ended June 30		
Utility Energy Segment	2009	B (W)	2008
		(Millions of Dollars)	
Operating Revenues			
Electric	$651.1	($18.8)	$669.9
Gas	181.6	(84.1)	265.7
Other	7.2	(0.7)	7.9
Total Operating Revenues	839.9	(103.6)	943.5
Fuel and Purchased Power	254.8	44.3	299.1
Cost of Gas Sold	102.1	83.4	185.5

Gross Margin	483.0	24.1	458.9
Other Operating Expenses			
Other Operation and Maintenance	341.2	12.1	353.3
Depreciation, Decommissioning and Amortization	78.8	(3.6)	75.2
Property and Revenue Taxes	27.9	(0.7)	27.2
Total Operating Expenses	804.8	135.5	940.3
Amortization of Gain	55.1	(31.9)	87.0

Operating Income

$90.2

$ -

$90.2

In January 2008, Wisconsin Electric received a rate order from the PSCW that authorized a 17.2% increase in electric rates to recover increased costs associated with transmission expenses, our 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 during the first quarter of 2008 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.

Electric Utility Revenues and Sales

The following table compares electric utility operating revenues and MWh sales by customer class during the second quarter of 2009 with the second quarter of 2008:

	Three Months Ended June 30					
	Electric Revenues			MWh Sales		
Electric Utility Operations	2009	B (W)	2008	2009	B (W)	2008
	(Millions of Dollars)			(Thousands)		
Customer Class						
Residential	$231.4	$10.5	$220.9	1,881.8	3.7	1,878.1
Small Commercial/Industrial	214.5	(6.5)	221.0	2,104.0	(119.6)	2,223.6
Large Commercial/Industrial	147.3	(26.6)	173.9	2,203.3	(615.1)	2,818.4
Other-Retail	5.1	0.2	4.9	38.3	(0.2)	38.5
Total Retail	598.3	(22.4)	620.7	6,227.4	(731.2)	6,958.6
Wholesale-Other	22.9	(7.4)	30.3	243.0	(328.6)	571.6
Resale-Utilities	5.8	(2.8)	8.6	214.4	97.2	117.2
Other Operating	24.1	13.8	10.3	-	-	-
Total	$651.1	($18.8)	$669.9	6,684.8	(962.6)	7,647.4
Weather -- Degree Days (a)						
Heating (954 Normal)				946	(16)	962
Cooling (167 Normal)				134	25	109

(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 decreased by $18.8 million, or approximately 2.8%, when compared to the second quarter of 2008. Our total electric sales volumes decreased by approximately 12.6% as compared to the second quarter of 2008. Total retail sales declined nearly 10.5%, with retail sales volumes to our small and large commercial and industrial customers declining by approximately 10.6%. The primary reason for the reduced sales volumes relates to a continued decline in economic conditions during the second quarter of 2009 as compared to the same period in 2008.

For the remainder of 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. In April 2009, the PSCW approved our request to decrease our Wisconsin retail electric rates for calendar year 2009 due to a decrease in fuel and purchased power costs. We also expect to continue to see a reduction in revenues as a result of this approval, which is expected to reduce revenues by approximately $45.8 million for calendar year 2009. For more information on the fuel cost decrease filing, see Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters -- 2009 Fuel Cost Decrease Filing.

We estimate that the decrease in electric revenue was offset in part by an increase of $31.9 million as a result of fewer bill credits to our customers from the sale of Point Beach during the second 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 -- Three

Months Ended June 30, 2009.

Our electric revenues were $10.0 million higher in the second quarter of 2009 as compared to 2008 because of a one-time entry related to MISO RSG credits that was not made in the second quarter of 2008. The second quarter entry reversed a first quarter charge to revenues. During the first quarter of 2009, the PSCW ordered us to refund $10.0 million of anticipated RSG credits that we hoped to receive from MISO in 2009. As discussed in the Form 10-Q for the first quarter of 2009, we reduced our revenues by $10.0 million because of the PSCW order. We did not record a receivable for the anticipated RSG credits because we believed that the ultimate recovery of the credits from MISO was uncertain. In the second quarter of 2009, the FERC issued a notice that significantly reduced the amount of RSG credits we hoped to receive from MISO. As a result of the FERC ruling, we requested and received an order from the PSCW that allowed us to record a regulatory asset for RSG credits that we refunded to customers that we do not ultimately expect to receive from MISO. The PSCW order allowed us to

reverse the $10.0 million charge to revenues that we recorded in the first quarter of 2009. For further information on the RSG credits see Factors Affecting Results, Liquidity and Capital Resources -- Electric Transmission and Energy Markets.

We estimate that our operating revenues for the second quarter of 2009 were $7.3 million higher when compared to the same period in 2008 because of warmer weather, as measured in cooling degree days. While the second quarter of 2009 was 19.8% cooler than normal, it was 22.9% warmer than the same period in 2008.

Fuel and Purchased Power

Our fuel and purchased power costs decreased by $44.3 million, or 14.8%, when compared to the second quarter of 2008. This decline was caused by lower MWh sales and 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 second quarter of 2009 with the second 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 operating revenues decreased by $84.1 million, or 31.7%, primarily due to lower natural gas prices.

	Three Months Ended June 30		
	2009	B (W)	2008
	(Millions of Dollars)		
Gas Operating Revenues	$181.6	($84.1)	$265.7
Cost of Gas Sold	102.1	83.4	185.5
Gross Margin	$79.5	($0.7)	$80.2

The following table compares gas utility gross margin and natural gas therm deliveries by customer class during the second quarter of 2009 with the second quarter of 2008.

	Three Months Ended June 30					
	Gross Margin			Therm Deliveries		
Gas Utility Operations	2009	B (W)	2008	2009	B (W)	2008
	(Millions of Dollars)			(Millions)		
Customer Class						
Residential	$51.4	$2.1	$49.3	111.5	8.2	103.3
Commercial/Industrial	15.1	(1.2)	16.3	64.1	(2.5)	66.6
Interruptible	0.4	(0.1)	0.5	3.9	(0.5)	4.4
Total Retail	66.9	0.8	66.1	179.5	5.2	174.3
Transported Gas	10.1	(1.3)	11.4	199.3	12.2	187.1
Other	2.5	(0.2)	2.7	-	-	-
Total	$79.5	($0.7)	$80.2	378.8	17.4	361.4
Weather -- Degree Days (a)						
Heating (954 Normal)				946	(16)	962

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

Our gas margins decreased by $0.7 million, or approximately 0.9%, when compared to the second quarter of 2008. During the second quarter of 2009, we experienced slightly warmer weather than in the same period during 2008. As measured by heating degree days, the second quarter of 2009 was 1.7% warmer than the same period in 2008 and 0.8% warmer than normal.

Other Operation and Maintenance Expense

Our other operation and maintenance expense decreased by $12.1 million, or approximately 3.4%, when compared to the second quarter of 2008. This decrease is primarily related to reduced operating expenses at our power plants and electric distribution system.

Depreciation, Decommissioning and Amortization Expense

Our depreciation, decommissioning and amortization expense increased by $3.6 million, or approximately 4.8%, when compared to the second quarter of 2008. This increase was the result of higher depreciation related to new projects, including the Blue Sky Green Field wind project that was placed into service in May 2008.

Amortization of Gain

In connection with the September 2007 sale of Point Beach, we reached agreements 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. During the second quarter of 2009 and 2008, we issued approximately $55.1 million and $87.0 million of bill credits, respectively.

NON-UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

Our non-utility energy segment contributed $30.8 million of operating income for the second quarter of 2009 as compared to $20.0 million for the second quarter of 2008. The increase primarily relates to earnings from PWGS 2, which was placed into service in May 2008, and from the water intake system for Oak Creek that was placed in service in January 2009.

CONSOLIDATED OTHER INCOME, NET

Other income, net decreased by approximately $0.6 million, or 7.6%, when compared to the second quarter of 2008. This decrease relates to reduced property sales during the second quarter of 2009 as compared to the same period in 2008.

CONSOLIDATED INTEREST EXPENSE, NET

	Three Months Ended June 30	
Interest Expense	2009	2008
	(Millions of Dollars)	
Gross Interest Costs	$58.8	$56.5
Less: Capitalized Interest	19.0	21.1
Interest Expense, net	$39.8	$35.4

Our gross interest costs increased by $2.3 million during the second quarter of 2009 primarily due to higher debt balances as a result of our construction programs, which was partially offset by lower short-term interest rates. Our capitalized interest decreased by $2.1 million due to a reduction in CWIP balances during the second quarter of 2009 as compared to the same period in 2008. In May 2008, PWGS 2 and the Blue Sky Green Field wind project were completed. Additionally, in January 2009, the water intake system that will serve both the existing units at Oak Creek and OC 1 and OC 2 was placed in service. As a result, our net interest expense increased by $4.4 million, or 12.4%, as compared to the second quarter of 2008.

CONSOLIDATED INCOME TAXES

For the second quarter of 2009, our effective tax rate applicable to continuing operations was 37.3% compared to 37.1% for the second quarter of 2008. For additional information, see Note H -- Income Taxes in our 2008 Annual Report on Form 10-K. We expect our 2009 annual effective tax rate to be between 35% and 37%.

RESULTS OF OPERATIONS -- SIX MONTHS ENDED JUNE 30, 2009

CONSOLIDATED EARNINGS

The following table compares our operating income by business segment and our net income during the first six months of 2009 with the first six months of 2008 including favorable (better (B)) or unfavorable (worse (W)) variances:

	Six Months Ended June 30		
	2009	B (W)	2008
	(Millions of Dollars)		
Utility Energy Segment	$306.5	$10.1	$296.4
Non-Utility Energy Segment	58.7	24.5	34.2
Corporate and Other	(3.0)	2.2	(5.2)
Total Operating Income	362.2	36.8	325.4
Equity in Earnings of Transmission Affiliate	28.7	5.1	23.6
Other Income, net	13.6	(4.9)	18.5
Interest Expense, net	80.6	(6.0)	74.6
	323.9	31.0	292.9

Income from Continuing Operations Before Income Taxes			
Income Taxes	119.0	(7.3)	111.7
Income from Continuing Operations	204.9	23.7	181.2
Income (Loss) from Discontinued Operations, Net of Tax	0.3	0.3	-
Net Income	$205.2	$24.0	$181.2
Diluted Earnings Per Share	$1.74	$0.21	$1.53

UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

Our utility energy segment contributed $306.5 million of operating income during the first six months of 2009, an increase of $10.1 million, or 3.4%, compared with the first six months of 2008. The following table summarizes the operating income of this segment between the comparative periods:

	Six Months Ended June 30		
Utility Energy Segment	2009	B (W)	2008
		(Millions of Dollars)	
Operating Revenues			
Electric	$1,344.7	$7.6	$1,337.1
Gas	868.5	(147.2)	1,015.7
Other	22.3	(0.9)	23.2
Total Operating Revenues	2,235.5	(140.5)	2,376.0
Fuel and Purchased Power	522.4	115.9	638.3
Cost of Gas Sold	604.7	141.0	745.7
Gross Margin	1,108.4	116.4	992.0
Other Operating Expenses			
Other Operation and Maintenance	707.9	30.7	738.6
Depreciation, Decommissioning and Amortization	157.3	(8.6)	148.7
Property and Revenue Taxes	56.0	(1.7)	54.3
Total Operating Expenses	2,048.3	277.3	2,325.6
Amortization of Gain	119.3	(126.7)	246.0
Operating Income	$306.5	$10.1	$296.4

The increase in Operating Income for the six months ended June 30, 2009, as compared to the same period in 2008 was primarily caused by favorable recoveries of revenues associated with fuel and purchased power. During the first six months of 2009, we experienced favorable fuel recoveries of approximately $24 million. During the same period in 2008, we experienced unfavorable fuel recoveries of approximately $20 million. While we experienced a net $44 million positive increase in fuel recoveries in the first six months of 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 the PSCW's approval of the request we filed to reduce Wisconsin Electric retail electric rates for calendar year 2009. For additional information on the rate filing, see Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters -- 2009 Fuel Cost Decrease Filing.

Electric Utility Revenues and Sales

The following table compares electric utility operating revenues and MWh sales by customer class during the first six months of 2009 with the first six months of 2008:

	Six Months Ended June 30					
	Electric Revenues			MWh Sales		
Electric Utility Operations	2009	B (W)	2008	2009	B (W)	2008
	(Millions of Dollars)			(Thousands)		
Customer Class						
Residential	$494.3	$25.9	$468.4	4,013.8	(73.0)	4,086.8
Small Commercial/Industrial	442.2	10.5	431.7	4,383.7	(172.6)	4,556.3
Large Commercial/Industrial	292.4	(37.4)	329.8	4,443.0	(1,100.9)	5,543.9
Other - Retail	10.8	0.3	10.5	80.6	(2.5)	83.1
Total Retail	1,239.7	(0.7)	1,240.4	12,921.1	(1,349.0)	14,270.1
Wholesale - Other	52.4	(11.6)	64.0	712.3	(481.1)	1,193.4
Resale - Utilities	23.8	9.7	14.1	691.5	378.1	313.4
Other Operating	28.8	10.2	18.6	-	-	-
Total	$1,344.7	$7.6	$1,337.1	14,324.9	(1,452.0)	15,776.9
Weather -- Degree Days (a)						
Heating (4,194 Normal)				4,404	(111)	4,515
Cooling (168 Normal)				134	25	109

(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 $7.6 million, or 0.6%, when compared to the first six months of 2008. We estimate that revenues were $47.2 million higher due to pricing increases that we received during January 2008 as part of the 2008 PSCW rate case that were in effect for all six months in 2009, as well as net pricing increases we received from the PSCW related to fuel. We also estimate that our electric revenues increased by $41.7 million as a result of fewer bill credits to our customers from the sale of Point Beach during the first six months of 2009 as compared to the same period in 2008. For more information on bill credits, see Amortization of Gain in Results of Operations -- Six Months Ended June 30, 2009.

We estimate that warmer weather during the first half of 2009 as compared to the first half of 2008 increased operating revenues by approximately $5.1 million. As measured by cooling degree days, the first six months of 2009 were approximately 22.9% warmer as compared to the first six months of 2008.

Our total electric sales volumes decreased by approximately 9.2%, with retail sales volumes declining nearly 9.5%. Approximately 8.9% of the decline in retail sales volumes relates to sales to 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 six months of 2009 as compared to the same period in 2008.

For a discussion of anticipated impacts of the downturn in the economy and the April 2009 fuel cost decrease filing for the remainder of 2009, see Results of Operations -- Three Months Ended June 30, 2009.

Fuel and Purchased Power

Our fuel and purchased power costs decreased by $115.9 million, or 18.2%, when compared to the first six months of 2008. The largest factor related to this decrease was a $41.2 million one-time amortization of deferred fuel costs pursuant to the January 2008 PSCW rate order. Adjusted for the one-time amortization, our fuel and purchased power costs decreased by $74.7 million, or 11.7%. This decline was caused by lower MWh sales and 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 six months of 2009 with the first six months 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 operating revenues decreased by $147.2 million, or 14.5%, primarily due to lower natural gas prices and milder weather.

	Six Months Ended June 30		
	2009	B (W)	2008
	(Millions of Dollars)		
Gas Operating Revenues	$868.5	($147.2)	$1,015.7
Cost of Gas Sold	604.7	141.0	745.7
Gross Margin	$263.8	($6.2)	$270.0

The following table compares gas utility gross margin and natural gas therm deliveries by customer class during the first six months of 2009 with the first six months of 2008:

	Six Months Ended June 30					
	Gross Margin			Therm Deliveries		
Gas Utility Operations	2009	B (W)	2008	2009	B (W)	2008
	(Millions of Dollars)			(Millions)		
Customer Class						
Residential	$169.4	($1.5)	$170.9	501.5	(10.6)	512.1
Commercial/Industrial	62.5	(2.3)	64.8	295.4	(11.6)	307.0
Interruptible	1.1	(0.2)	1.3	11.0	(1.9)	12.9
Total Retail	233.0	(4.0)	237.0	807.9	(24.1)	832.0
Transported Gas	25.3	(2.3)	27.6	472.2	(9.6)	481.8
Other	5.5	0.1	5.4	-	-	-
Total	$263.8	($6.2)	$270.0	1,280.1	33.7	1,313.8
Weather -- Degree Days (a)						
Heating (4,194 Normal)				4,404	(111)	4,515

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

Our gas margins decreased by $6.2 million, or 2.3%, when compared to the first six months of 2008. We estimate that a decline in sales volumes as a result of milder weather and a decline in economic conditions caused margins to decrease by approximately $7.2 million during the first six months of 2009 as compared to the same period in 2008. As measured by heating degree days, the first six months of 2009 were 2.5% warmer than the same period in 2008 and 5.0% cooler than normal. Pricing increases that we received during January 2008 as part of the January 2008 PSCW rate case that were in effect for all six months in 2009 partially offset this decrease.

Other Operation and Maintenance Expense

Our other operation and maintenance expense decreased by approximately $30.7 million, or 4.2%, when compared to the first six months 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 in January 2008. The January 2008 PSCW rate order, which was in effect for all six months 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 $15.9 million higher in the first six months of 2009 as compared to the same period in 2008.

Depreciation, Decommissioning and Amortization Expense

Our depreciation, decommissioning and amortization expense increased by $8.6 million, or approximately 5.8%, when compared to the first six months of 2008. This increase was the result of higher depreciation related to new projects, including the Blue Sky Green Field wind project that was placed into service in May 2008.

Amortization of Gain

In connection with the September 2007 sale of Point Beach, we reached agreements 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 six months ended June 30:

Amortization of Gain	2009	2008
	(Millions of Dollars)	
Bill Credits - Retail	$119.3	$161.0
One-Time Amortization	-	85.0
Total Amortization of Gain	$119.3	$246.0

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 the third quarter of 2008, as well as an expected approximately $108 million annual decrease in bill credits to retail customers.

NON-UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

Our non-utility energy segment contributed $58.7 million of operating income for the first six months of 2009 as compared to $34.2 million for the first six months of 2008. The increase primarily relates to earnings from PWGS 2, which was placed into service in May 2008, and the water intake system at Oak Creek which was placed into service in January 2009.

CONSOLIDATED OTHER INCOME, NET

Other income, net decreased by approximately $4.9 million, or 26.5%, when compared to the first six months of 2008. This decrease primarily relates to reduced property sales during the first six months of 2009 as compared to the same period in 2008.

CONSOLIDATED INTEREST EXPENSE, NET

Interest Expense	Six Months Ended June 30	
	2009	2008
	(Millions of Dollars)	
Gross Interest Costs	$118.8	$117.9
Less: Capitalized Interest	38.2	43.3
Interest Expense, net	$80.6	$74.6

Our gross interest costs increased by $0.9 million, or 0.8%, during the six months ended June 30, 2009 primarily due to higher debt balances as a result of our construction programs, which were partially offset by lower short-term interest rates. Our capitalized interest decreased by $5.1 million due to a reduction in CWIP balances during the first six months of 2009 as compared to the same period in 2008. In May 2008, PWGS 2 and the Blue Sky Green Field wind project were completed. Additionally, in January 2009, the water intake system that will serve both the existing units at Oak Creek and OC 1 and OC 2 was placed in service. As a result, our net interest expense increased by $6.0 million, or 8.0%, as compared to the first six months of 2008.

CONSOLIDATED INCOME TAXES

For the first six months of 2009, our effective tax rate applicable to continuing operations was 36.7% compared to 38.1% for the first six months of 2008. For additional information, see Note H -- Income Taxes in our 2008 Annual Report on Form 10-K. We expect our 2009 annual effective tax rate to be between 35% and 37%.

LIQUIDITY AND CAPITAL RESOURCES

CASH FLOWS

The following summarizes our cash flows from continuing operations during the first six months of 2009 and 2008:

Wisconsin Energy Corporation	Six Months Ended June 30	
	2009	2008
	(Millions of Dollars)	

Cash Provided by (Used in)		
Operating Activities	$232.4	$573.7
Investing Activities	($306.3)	($534.4)
Financing Activities	$53.9	($40.1)

Operating Activities

Cash provided by operating activities was $232.4 million during 2009, which was $341.3 million lower than 2008. Although we experienced an increase in net income and depreciation during the first six months of 2009, there were two large factors that reduced cash from operations. During the first six months of 2009, we contributed $289.3 million to our benefit plans as compared to approximately $48.4 million during the first six months of 2008. The second factor related to an increase in cash used for working capital related to our coal and natural gas inventories.

Investing Activities

Cash used in investing activities was $306.3 million during the six months ended June 30, 2009, which was $228.1 million lower than the same period in 2008. This decline reflects lower capital expenditures during the first six months of 2009 and cash flows from the release of restricted cash.

During the first six months of 2009, our capital expenditures decreased $276.9 million primarily due to the reduction in the capital expenditures for our Oak Creek expansion and PWGS 2, which was completed in 2008.

During the first six months of 2009, we released $51.0 million less from restricted cash as compared to the same period in 2008. As background, 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.

Financing Activities

Cash provided by financing activities during the six months ended June 30, 2009 was $53.9 million, compared to cash used in financing activities during the same period in 2008 of $40.1 million. During the first six months of 2009, we paid approximately $78.9 million in cash dividends and increased our debt levels by a net amount of approximately $136.1 million.

During the first six months of 2009, we received proceeds of $6.3 million related to the exercise of stock options, compared with $7.6 million during the same period in 2008. Instead of issuing new shares for these stock options, we instructed our plan agent to purchase common stock in the open market at a cost of $10.5 million, compared with $14.9 million during the first six months of 2008. This cost is included in Purchase of common stock on our Consolidated Condensed Statements of Cash Flows.

CAPITAL RESOURCES AND REQUIREMENTS

Capital Resources

We anticipate meeting our capital requirements during the remaining six months of 2009 primarily through internally generated funds and short-term borrowings, supplemented by the issuance of intermediate or long-term debt securities depending on market conditions and other factors. Beyond 2009, we anticipate meeting our capital requirements through internally generated funds supplemented, when required, by short-term borrowings and the issuance of debt securities.

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 arrangements, access to capital markets and internally generated cash.

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

An affiliate of Lehman Brothers Holdings, which filed for bankruptcy in September 2008, provided approximately $80 million of commitments under our bank back-up credit facilities on a consolidated basis. We have no current plans to replace Lehman's commitments. Excluding Lehman's commitments, as of June 30, 2009, we had approximately $1.6 billion of available, undrawn lines under our bank back-up credit facilities. As of June 30, 2009, we had approximately $780.2 million of short-term debt outstanding on a consolidated basis that was supported by the available lines of credit.

We review our bank back-up credit facility needs on an ongoing basis and expect to be able to maintain adequate credit facilities to support our operations. The following table summarizes such facilities as of June 30, 2009:

Company	Total Facility *	Letters of Credit	Credit Available *	Facility Expiration
		(Millions of Dollars)		
Wisconsin Energy	$857.5	$1.5	$856.0	April 2011
Wisconsin Electric	$476.4	$4.5	$471.9	March 2011
Wisconsin Gas	$285.8	$ -	$285.8	March 2011

* Excludes Lehman's commitments

The following table shows our actual capitalization structure as of June 30, 2009, as well as an adjusted capitalization structure that we believe is consistent with the manner in which the majority of rating agencies currently view the Junior Notes:

Capitalization Structure	Actual	Adjusted
	(Millions of Dollars)	
Common Equity	$3,467.1	$3,717.1
Preferred Stock of Subsidiary	30.4	30.4
Long-Term Debt (including current maturities)	4,093.1	3,843.1
Short-Term Debt	780.2	780.2
Total Capitalization	$8,370.8	$8,370.8
Total Debt	$4,873.3	$4,623.3
Ratio of Debt to Total Capitalization	58.2%	55.2%

Included in Long-Term Debt on our Consolidated Condensed Balance Sheets as of June 30, 2009 is $500 million aggregate principal amount of the Junior Notes. The adjusted presentation attributes $250 million of the Junior Notes to Common Equity and $250 million to Long-Term Debt. We believe this presentation is consistent with the 50% equity credit the majority of rating agencies currently attribute to the Junior Notes.

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

Access to capital markets at a reasonable cost is determined in large part by credit quality. The following table summarizes the ratings of our debt securities and the debt securities and preferred stock of our subsidiaries by S&P, Moody's and Fitch as of June 30, 2009:

	S&P	Moody's	Fitch
Wisconsin Energy			
Commercial Paper	A-2	P-2	F2
Unsecured Senior Debt	BBB+	A3	A-
Unsecured Junior Notes	BBB-	Baa1	BBB+
Wisconsin Electric			
Commercial Paper	A-2	P-1	F1
Secured Senior Debt	A-	Aa3	AA-
Unsecured Debt	A-	A1	A+
Preferred Stock	BBB	A3	A
Wisconsin Gas			
Commercial Paper	A-2	P-1	F1
Unsecured Senior Debt	A-	A1	A+

Wisconsin Energy Capital Corporation			
Unsecured Debt	BBB+	A3	A-

In July 2009, S&P affirmed the ratings of Wisconsin Energy, Wisconsin Electric, Wisconsin Gas and Wisconsin Energy Capital Corporation and revised the ratings outlooks assigned each company from positive to stable.

In June 2009, Fitch affirmed the ratings of Wisconsin Energy, Wisconsin Electric, Wisconsin Gas and Wisconsin Energy Capital Corporation and the stable ratings outlook of Wisconsin Gas. Fitch also

revised the ratings outlooks of Wisconsin Energy, Wisconsin Electric and Wisconsin Energy Capital Corporation from stable to negative.

The ratings outlooks assigned by Moody's for Wisconsin Energy, Wisconsin Electric, Wisconsin Gas and Wisconsin Energy Capital Corporation are all stable.

Subject to other factors affecting the credit markets as a whole, we believe these security ratings should provide a significant degree of flexibility in obtaining funds on competitive terms. However, these security ratings reflect the views of the rating agencies only. An explanation of the significance of these ratings may be obtained from each rating agency. Such ratings are not a recommendation to buy, sell or hold securities, but rather an indication of creditworthiness. Any rating can be revised upward or downward or withdrawn at any time by a rating agency if it decides that the circumstances warrant the change. Each rating should be evaluated independently of any other rating.

Capital Requirements

Capital requirements during the remainder of 2009 are expected to be principally for capital expenditures related to the Oak Creek expansion and environmental controls at our existing Oak Creek generating units. Our 2009 annual consolidated capital expenditure budget is approximately $875 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 construction projects, commodity contracts and other payment obligations. We continue to believe that these agreements do not have, and are not reasonably likely to have, a current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to our investors. For further information, see Note 9 -- Guarantees and Note 11 -- 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 $22.6 billion as of June 30, 2009 compared with $23.1 billion as of December 31, 2008. Our total contractual obligations and other commercial commitments as of June 30, 2009 decreased compared with December 31, 2008 primarily due to periodic payments related to these types of obligations which were greater than new commitments made in the ordinary course of business during the six month period ended June 30, 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, our PTF strategy, utility rates and regulatory matters, electric system reliability, environmental matters, legal matters, industry restructuring and competition and other matters.

POWER THE FUTURE

Under our PTF strategy, we expect to meet a significant portion of our future generation needs through the construction of the PWGS and the Oak Creek expansion. We Power is leasing the PWGS units to Wisconsin Electric under long-term leases, and we expect Wisconsin Electric to recover the lease

payments in its electric rates. The Oak Creek expansion is currently being constructed by We Power, and we expect Wisconsin Electric to recover future lease payments in its 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 us 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 us 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 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 first claim is based on the alleged impact of severe weather and certain labor-related matters. Bechtel is requesting approximately $413 million in costs related to changed weather and labor conditions. Bechtel has reserved the right to request future additional costs and schedule relief.

The weather events for which Bechtel seeks cost and schedule relief are (i) extreme winds from September 2006 through April 2007, (ii) snowstorms from December 2007 through April 2008, and (iii) rain storms in June 2008. Bechtel contends that these weather events constituted events of force majeure. We are conducting a detailed analysis of Bechtel's force majeure claim to determine whether Bechtel is entitled to any schedule relief as a result of these weather events. However, we currently believe Bechtel's request for cost relief related to its claim of force majeure is without merit. Bechtel also claims that these same weather events constituted changed local conditions that could not have reasonably been foreseen and that caused it to incur additional costs. We believe that the claim for additional costs and schedule relief based on a change in local conditions is without merit.

The alleged changes in labor conditions for which Bechtel seeks cost and schedule relief are (i) a significant shortage in the availability of craft labor, (ii) significant increases in competing projects, (iii) the overtime and per diems allegedly necessary to attract labor, and (iv) alleged restrictions that our Project Labor Agreement placed on Bechtel's ability to attract and retain craft labor. Bechtel describes these as changed local conditions for which it believes we should bear the risk. Under the terms of the contract, we agreed to accept labor-related risk only as to wage escalation in excess of 4% annually as measured by published wage bulletins. Therefore, we believe that this claim is without merit.

Bechtel's second claim of approximately $72 million seeks cost and schedule relief for the alleged effects of ERS-directed changes and delays allegedly caused by ERS prior to the issuance of the FNTP in July 2005 as follows: (i) the delay in issuing certain limited notices to proceed; (ii) the delay in issuing the FNTP until the final resolution of litigation brought by certain opposition groups that challenged the CPCN for the Oak Creek expansion; (iii) the imposition of additional limits to third party cancellation charges which allegedly restricted Bechtel's ability to issue purchase orders; (iv) the reduction of the pre-FNTP monthly payments below the amounts required by the contract; and (v) the request by ERS to perform design studies and issue design changes during the pre-FNTP period. We believe that this claim is without merit. We currently believe Bechtel was fully compensated for any and all impacts of the delayed start as indicated in certain change orders entered into between ERS and Bechtel prior to the start of construction of the Oak Creek expansion. Further, we do not believe that the contract provides for relief based upon the cumulative impact of change orders.

We continue to believe that the only circumstances and events for which we currently retain price adjustment risk under the contract are force majeure, wage escalation in excess of 4% annually as

measured by published wage bulletins, delays caused by us, changes in scope or performance requested by us and unforeseen sub-surface ground conditions.

Based on Bechtel's July 2008 communication, we notified Bechtel on September 29, 2008 that we were 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 subsequently agreed with Bechtel to combine these issues and Bechtel's claim into one mediation. Mediation was unsuccessful and, therefore, as required by the contract, the parties submitted the claims to binding arbitration, which we anticipate 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. Bechtel fell behind this revised target schedule in moving from construction to start-up, but developed a recovery plan and added resources in an effort to recover lost time. Bechtel has made, and continues to make, significant construction and start-up progress; however, at this time it has not fully kept pace with its revised schedule.

UTILITY RATES AND REGULATORY MATTERS

2010 Rate Case:

On March 13, 2009, Wisconsin Electric and Wisconsin Gas initiated rate proceedings with the PSCW. Wisconsin Electric initially asked the PSCW to approve a rate increase for its Wisconsin retail electric customers of approximately $76.5 million, or 2.8%, and a rate increase for its natural gas customers of approximately $22.1 million, or 3.6%. In addition, Wisconsin Electric has requested increases of approximately $1.4 million, or 5.8%, and approximately $1.3 million, or 6.8%, for its Valley steam utility customers and Milwaukee County steam utility customers, respectively. Wisconsin Gas has asked the PSCW to approve a rate increase for its natural gas customers of approximately $38.9 million, or 4.6%. Both Wisconsin Electric and Wisconsin Gas have requested that these rates become effective January 1, 2010.

In July 2009, Wisconsin Electric filed supplemental testimony with the PSCW updating its rate increase request for retail electric customers to reflect the impact of lower sales as a result of the decline in the economy. The effect of the change results in Wisconsin Electric increasing its request from $76.5 million to $126.0 million. However, those same lower sales also made available $24.0 million in added bill credits from the sale of Point Beach, resulting in a net increase to customers of 3.9%.

As part of its electric rate proceeding, Wisconsin Electric has 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.
- Wisconsin Electric will continue to receive 100% AFUDC for capital expenditures on environmental control projects at its 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, Wisconsin Electric 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.

43

2010 Michigan Price Increase Request:

In July 2009, Wisconsin Electric filed a $42 million rate increase request with the MPSC, primarily to recover the costs of PTF projects. This rate increase is expected to be implemented in three phases throughout 2010. We expect the first phase to be effective in early 2010. A final decision from the MPSC is expected in July 2010. Pursuant to recently enacted Michigan legislation, we may, upon the satisfaction of certain conditions, self-implement a rate increase request, subject to refund with interest.

2009 Fuel Cost Decrease Filing:

Wisconsin Electric operates under a fuel cost adjustment clause for fuel and purchased power costs associated with the generation and delivery of electricity to its retail customers in Wisconsin. In April 2009, based on three months of actual fuel cost data and nine months of projected data, Wisconsin Electric forecasted that its monitored fuel cost for 2009 would fall outside the range prescribed by the PSCW and would be less than the monitored fuel cost reflected in then authorized rates. Therefore, in April 2009, Wisconsin Electric 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, Wisconsin Electric and Wisconsin Gas initiated rate proceedings. Wisconsin Electric asked the PSCW to approve a comprehensive plan which would result in price increases of $648.6 million for its 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, Wisconsin Electric requested a 1.8% price increase in 2008 for its gas customers and an approximately 16.0% price increase in 2008 for all steam customers in metropolitan Milwaukee. Wisconsin Gas filed for a 4.1% price increase in 2008 for its gas customers. Electric pricing increases were needed to allow us to continue progress on previously approved initiatives, including: costs associated with our 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 Wisconsin Electric and Wisconsin Gas as follows

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- $389.1 million (17.2%) in electric rates for Wisconsin Electric - 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 from Wisconsin Electric;
- $3.6 million (11.2%) for steam service from Wisconsin Electric; and
- $20.1 million (2.2%) for natural gas service from Wisconsin Gas.

In addition, the PSCW lowered the return on equity for Wisconsin Electric and Wisconsin Gas 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.

Wisconsin Electric expects to provide a total of approximately $710.0 million of bill credits to its Wisconsin customers over the three year period ending December 31, 2010. As of June 30, 2009, we have issued approximately $404.5 million of bill credits to Wisconsin retail customers.

2008 Michigan Price Increase

: In January 2008, Wisconsin Electric 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

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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, Wisconsin Electric 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 and $10.0 million of RSG credits we hoped to receive from MISO. The refund was issued during the second quarter of 2009.

Oak Creek Air Quality Control System Approval:

In July 2008, we received approval from the PSCW granting Wisconsin Electric 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 has been included in our previous 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 make recommendations regarding 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 $55 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 -- Utility Rates and Regulatory Matters in Item 7 of our 2008 Annual Report on Form 10-K for additional information regarding our utility rates and other regulatory matters.

WIND GENERATION

In July 2008, we completed the purchase of rights to a new wind farm site in Central Wisconsin, Glacier Hills Wind Park, and filed a request for a CPCN with the PSCW in October 2008. We entered into a conditional turbine agreement for the new wind facility and filed a revised, lower cost estimate with the PSCW in May 2009 of $335.2 million to $413.5 million, excluding AFUDC. We currently expect to install 90 wind turbines with generating capacity of up to approximately 207 MW, subject to the final site configuration. We expect 2012 to be the first full year of operation, subject to regulatory approvals.

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 relatively 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 has been able to reduce overall ancillary services costs in the MISO footprint. The MISO ancillary services market has enabled MISO to assume significant balancing area responsibilities such as frequency control and disturbance control.

In MISO, base transmission costs are currently being paid by 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. In July 2007, MISO commenced with the resettlement of the market in response to the orders. The resettlement was completed in January 2008 and resulted in a net cost increase of $7.8 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, several parties, including Wisconsin Electric, filed for rehearing and/or clarification with FERC.

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 ordered 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.

In May 2009, FERC issued an order denying rehearing on substantive matters for the rate period beginning August 10, 2007. However, FERC modified the effective date of that rate to November 10, 2008, and ordered MISO to cease the ongoing resettlement and to reconcile all invoices and payments therein. Similarly, in June 2009, FERC dismissed rehearing requests, but waived refunds for the period April 25, 2006 through November 4, 2007. FERC also stated for the first time that it was waiving refunds for the period April 1, 2005 through April 24, 2006. We, along with others, have sought rehearing and/or appeal of the FERC's May and June 2009 determinations pertaining to refunds. In addition, there are contested compliance matters pending FERC review. The net effects of FERC's rulings are uncertain at this time.

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.

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, 2009 through May 31, 2010. The resulting ARR valuation and the secured FTRs should adequately mitigate our transmission congestion risk for that period.

LEGAL MATTERS

Cash Balance Pension Plan:

On June 30, 2009, a lawsuit by a retiree plaintiff was filed against the Plan. Counsel representing the plaintiff is attempting to seek certification for a class of plaintiffs including the plaintiff and other similarly situated plaintiffs. The complaint alleges that Plan participants who received a lump sum distribution under the Plan prior to their normal retirement age did not receive the full benefit to which they were entitled in violation of ERISA and are owed additional benefits, because the Plan failed to apply the correct interest crediting rate to project the cash balance account to their normal retirement age. We believe the Plan correctly calculated the lump-sum distributions. An adverse outcome of this lawsuit could affect our Plan funding and expense. We are currently unable to predict the final outcome or impact of this litigation.

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. Compliance with the NO_x emission reduction requirements under the Consent Decree has substantially mitigated 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. In July 2009, Wisconsin issued both a draft Attainment Demonstration and a Redesignation request. Based on our review of these drafts, we do not believe we would be subject to any further requirements to reduce emissions. The EPA must take final approval action once Wisconsin finalizes their submittals.

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 our new PTF generating units being leased by Wisconsin Electric 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.

The federal rule was challenged by a number of states including Wisconsin and Michigan. In February 2008, the U.S. Court of Appeals for the D.C. Circuit vacated CAMR and sent the rule back to the EPA for reconsideration. 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, SO_2 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 SO_2 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 Wisconsin Electric's 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.

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.

Climate Change Legislation:

Global warming is increasingly a concern for the energy industry. Federal and state legislative proposals have been introduced to regulate the emission of greenhouse gases, particularly CO_2, and the President and his administration have made it clear that they are focused on reducing such emissions. In addition, there have been international efforts seeking legally binding reductions in emissions of greenhouse gases.

The American Clean Energy and Security Act of 2009 (otherwise known as the Waxman-Markey Bill) passed the U.S. House of Representatives on June 26, 2009. The Bill, among other things, (i) establishes a federal renewable energy standard; (ii) permits energy efficiency measures to satisfy part of the renewable energy standard; and (iii) establishes a cap-and-trade-program to reduce greenhouse gas emissions from various sectors of the economy, including electric and natural gas utilities. The debate regarding federal climate legislation is ongoing in the U.S. Senate, which is considering similar legislation.

The Governors of both Michigan and Wisconsin have signed on to the "Midwestern Greenhouse Gas Reduction Accord" and the associated "platform" document developed through the Midwestern Governors Association. The stated goal of the platform is to "maximize the energy resources and economic advantages and opportunities of Midwestern states while reducing emissions of atmospheric CO_2 and other greenhouse gases". The group charged with developing a regional cap-and-trade system under this Accord has recommended a plan that calls for a 20% reduction in greenhouse gas emissions

from 2005 levels by 2020 and an 80% reduction by 2050. The group has stated that it prefers a federal cap-and-trade system, but it developed the plan in the event Congress fails to act by 2012.

We continue to monitor the legislative and regulatory developments in this area, including those in the U.S. Congress.

Depending on the extent of rate recovery, we anticipate that any cap-and-trade program that may be adopted, either at the federal or regional level, could have a material adverse impact on our electric generation and natural gas distribution operations. Such regulation could make some of our electric generating units uneconomic to maintain or operate, and could affect future results of operations, cash flows and possibly financial condition if such costs are not recovered through regulated rates.

There is no guarantee that we will be allowed to fully recover costs incurred to comply with any future legislation and/or regulation that requires a reduction in greenhouse gas emissions or that cost recovery will not be delayed or otherwise conditioned. Although we expect the regulation of greenhouse gas emissions could have a material adverse impact on our operations and rates, we believe it is premature to attempt to quantify the possible costs of the impacts.

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 it is difficult to predict at this time, such a finding or subsequent rulemaking could have a material adverse impact on our operations.

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 Energy Corporation, see Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations -- Factors Affecting Results, Liquidity and Capital Resources -- Market Risks and Other Significant Risks, in Part II of our 2008 Annual Report on Form 10-K.

ITEM 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures:

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

Internal Control Over Financial Reporting:

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

PART II -- OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

The following should be read in conjunction with Item 3. Legal Proceedings in Part I of our 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.

UTILITY RATES AND REGULATORY MATTERS

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

OTHER MATTERS

Cash Balance Pension Plan:

See Factors Affecting Results, Liquidity and Capital Resources -- Legal Matters in Management's Discussion and Analysis of Financial Condition and Results of Operations in Part I of this report for information concerning an alleged violation of ERISA by our cash balance pension plan.

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.

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

The following table sets forth information regarding the purchases of our equity securities made by or on behalf of us or any affiliated purchaser (as defined in Exchange Act Rule 10b-18) during the three-month period ended June 30, 2009.

Maximum
Approximate

2009	Total Number of Shares Purchased (a)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs
				(Millions of Dollars)
April 1- April 30	2,028	$39.81	-	$ -
May 1- May 31	-	-	-	$ -
June 1- June 30	-	-	-	$ -
Total	2,028	$39.81	-	$ -

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

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

At Wisconsin Energy's 2009 Annual Meeting of Stockholders held on May 7, 2009, stockholders voted on the following items with the following results:

Item 1 -- Election of Nine Directors for Terms Expiring in 2010:

The Board of Directors' nominees named below were elected as directors by the indicated votes and percentages cast for each nominee. Directors are elected by a plurality of the votes cast by the shares entitled to vote. Any shares not voted, whether by withheld authority, broker non-votes or otherwise, have no effect in the election of directors. There was no solicitation in opposition to the nominees proposed in our Proxy Statement.

Nominee	Shares For		Shares Withheld	
John F. Bergstrom	73,700,724	75.22%	24,276,372	24.78%

Barbara L. Bowles	95,654,860	97.62%	2,322,236	2.38%
Patricia W. Chadwick	96,569,708	98.56%	1,407,388	1.44%
Robert A. Cornog	95,723,993	97.70%	2,253,103	2.30%
Curt S. Culver	96,315,731	98.30%	1,661,365	1.70%
Thomas J. Fischer	96,086,641	98.07%	1,890,455	1.93%
Gale E. Klappa	95,209,940	97.17%	2,767,156	2.83%
Ulice Payne, Jr.	75,312,300	76.86%	22,664,796	23.14%
Frederick P. Stratton, Jr.	75,014,797	76.56%	22,962,299	23.44%

Item 2 --

Ratification of Deloitte & Touche LLP as independent auditors for 2009: The Audit and Oversight Committee of the Board of Directors has sole authority to select, evaluate and, where appropriate, terminate and replace the independent auditors. The Audit and Oversight Committee appointed Deloitte & Touche LLP as our independent auditors for the fiscal year ending December 31, 2009, subject to stockholder ratification. The Committee believes that stockholder ratification of this matter is important considering the critical role the independent auditors play in maintaining the integrity of our financial statements. Stockholders ratified Deloitte & Touche LLP as independent auditors for fiscal year 2009 by the following vote:

Shares Voted For	Percentage of Shares For	Shares Voted Against	Percentage of Shares Against	Shares Abstain	Percentage of Shares Abstain
95,016,926	96.97%	2,314,085	2.36%	646,085	0.67%

Of 116,914,008 voting shares outstanding as of the February 26, 2009 record date for the annual meeting, 97,977,096 shares (approximately 83.8% of the shares outstanding) were represented at the meeting.

Further information concerning these matters is contained in our Proxy Statement dated April 2, 2009 with respect to the 2009 Annual Meeting of Stockholders.

ITEM 5. OTHER INFORMATION

Effective April 30, 2009, we sold our water utility to the City of Mequon, Wisconsin for approximately $14.5 million. For further information on the sale of our water utility, see Note 5 -- Discontinued Operations in the Notes to Consolidated Condensed Financial Statements in this Form 10-Q.. We also reclassified the water utility results of operations as discontinued operations in the interim consolidated condensed income statements.

We have determined that the assets, liabilities and the results of the discontinued operations of the water utility were not material to our financial condition, results of operations or cash flows. However, we are required to retrospectively present the discontinued operations of our water utility as discontinued operations for all periods presented in future filings. The following table summarizes the net impacts of the discontinued operations of the water utility on our earnings as of December 31, 2008, 2007 and 2006:

	2008		2007 (In Millions)		2006	
	As Previously Reported	As Revised	As Previously Reported	As Revised	As Previously Reported	As Revised
Income from Continuing Operations	$358.6	$357.7	$336.5	$335.7	$312.5	$311.8
Income (Loss) from Discontinued Operations, Net of Tax	0.5	1.4	(0.9)	(0.1)	3.9	4.6
Net Income	$359.1	$359.1	$335.6	$335.6	$316.4	$316.4

54

ITEM 6. EXHIBITS

Exhibit No.

10 Material Contracts

10.1 Credit Agreement, dated as of April 6, 2006, among Wisconsin Energy Corporation, as Borrower, the Lenders identified therein, and JP Morgan Chase Bank, N.A., as Administrative Agent and Fronting Bank.

10.2 Credit Agreement, dated as of March 30, 2006, among Wisconsin Electric Power Company, as Borrower, the Lenders identified therein, and U.S. Bank National

Association, as Administrative Agent and Fronting Bank.

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

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

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

32 Section 1350 Certifications

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

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

101 Interactive Data File

SIGNATURES

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

WISCONSIN ENERGY CORPORATION
(Registrant)

/s/STEPHEN P. DICKSON

Date: August 4, 2009

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