WISCONSIN ENERGY CORP
Form 10-Q
November 02, 2012

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 September 30, 2012

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

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

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

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

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

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

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date (September 30, 2012):

Common Stock, $.01 Par Value,	230,070,094 shares outstanding.

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WISCONSIN ENERGY CORPORATION

FORM 10-Q REPORT FOR THE QUARTER ENDED SEPTEMBER 30, 2012

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DEFINITION OF ABBREVIATIONS AND INDUSTRY TERMS

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

Primary Subsidiaries	
We Power	W.E. Power, LLC
Wisconsin Electric	Wisconsin Electric Power Company
Wisconsin Gas	Wisconsin Gas LLC
Significant Assets	
OC 1	Oak Creek expansion Unit 1
OC 2	Oak Creek expansion Unit 2
PWGS 1	Port Washington Generating Station Unit 1
PWGS 2	Port Washington Generating Station Unit 2
VAPP	Valley Power Plant
Other Subsidiaries and Affiliates	
ATC	American Transmission Company LLC
Federal and State Regulatory Agencies	
CFTC	Commodity Futures Trading Commission
DOE	United States Department of Energy
DOJ	Wisconsin Department of Justice
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
WDNR	Wisconsin Department of Natural Resources
Environmental Terms	
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CSAPR	Cross-State Air Pollution Rule
MATS	Mercury and Air Toxics Standards
NOV	Notice of Violation
SO_2	Sulfur Dioxide
Other Terms and Abbreviations	
AQCS	Air Quality Control System
ARRs	Auction Revenue Rights
Compensation Committee	Compensation Committee of the Board of Directors
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
ERISA	Employee Retirement Income Security Act of 1974
Exchange Act	Securities Exchange Act of 1934, as amended
FTRs	Financial Transmission Rights
Junior Notes	

Wisconsin Energy's 2007 Series A Junior Subordinated Notes due 2067 issued in May 2007

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DEFINITION OF ABBREVIATIONS AND INDUSTRY TERMS

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

LMP	Locational Marginal Price
MISO	Midwest Independent Transmission System Operator, Inc.
OTC	Over-the-Counter
Plan	The Wisconsin Energy Corporation Retirement Account Plan
Point Beach	Point Beach Nuclear Power Plant
PTF	Power the Future
WPL	Wisconsin Power and Light Company, a subsidiary of Alliant Energy Corp.
Measurements	
Btu	British Thermal Unit(s)
Dth	Dekatherm(s) (One Dth equals one million Btu)
MW	Megawatt(s) (One MW equals one million Watts)
MWh	Megawatt-hour(s)
Watt	A measure of power production or usage
Accounting Terms	
AFUDC	Allowance for Funds Used During Construction
FASB	Financial Accounting Standards Board
GAAP	Generally Accepted Accounting Principles
OPEB	Other Post-Retirement Employee Benefits

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

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

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

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

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

- Timing, resolution and impact of pending and future rate cases and negotiations, including recovery of all costs associated with our Power the Future (PTF) strategy, as well as costs associated with environmental compliance, renewable generation, transmission service, distribution system upgrades, fuel and the Midwest Independent Transmission System Operator, Inc. (MISO) Energy Markets.

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

- The ability to control costs and avoid construction delays during the development and construction of new environmental controls and renewable generation.

- The impact of recent and future federal, state and local legislative and regulatory changes, including any changes in rate-setting policies or procedures; electric and gas industry restructuring initiatives; transmission or distribution system operation and/or administration initiatives; any required changes in facilities or operations to reduce the risks or impacts of potential terrorist activities or cybersecurity threats; required approvals for new construction, and the siting approval process for new generation and transmission facilities and new pipeline construction; changes to the Federal Power Act and related regulations and enforcement thereof by the Federal Energy Regulatory Commission (FERC) and other regulatory agencies; changes in allocation of energy assistance, including state public benefits funds; changes in environmental, tax and other laws and regulations to which we are subject; changes in the application of existing laws and regulations; and changes in the interpretation or enforcement of permit conditions by the permitting agencies.

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

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

- Current and future litigation, regulatory investigations, proceedings or inquiries, including FERC matters and Internal Revenue Service (IRS) audits and other tax matters.

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

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

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

- The financial performance of American Transmission Company LLC (ATC) and its corresponding contribution to our earnings.

- The impact of the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) and any regulations promulgated thereunder, including rules recently adopted and/or proposed by the Commodity Futures Trading Commission (CFTC) that may impact our hedging activities and related costs, and those relating to disclosures regarding the use of conflict minerals.

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

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

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

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

- The ability to obtain and retain short- and long-term contracts with wholesale customers.

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

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

- Foreign governmental, economic, political and currency risks.

- Other business or investment considerations that may be disclosed from time to time in our Securities and Exchange Commission (SEC) filings or in other publicly disseminated written documents, including the risk factors set forth in our Annual Report on Form 10-K for the year ended December 31, 2011.

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

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INTRODUCTION

Wisconsin Energy Corporation is a diversified holding company which conducts its operations primarily in two reportable segments: a utility energy segment and a non-utility energy segment. Unless qualified by their context when used in this document, the terms Wisconsin Energy, the Company, our, us or we refer to the holding company and all of its subsidiaries. Our primary subsidiaries are Wisconsin Electric Power Company (Wisconsin Electric), Wisconsin Gas LLC (Wisconsin Gas) and W.E. Power, LLC (We Power).

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

Non-Utility Energy Segment: Our non-utility energy segment consists primarily of We Power. We Power was formed in 2001 to design, construct, own and lease to Wisconsin Electric the new generating capacity included in our PTF strategy. See Item 1. Business and Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations in our 2011 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 2011 Annual Report on Form 10-K, including the financial statements and notes therein.

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PART I -- FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

WISCONSIN ENERGY CORPORATION
CONSOLIDATED CONDENSED INCOME STATEMENTS
(Unaudited)

	Three Months Ended September 30		Nine Months Ended September 30	
	2012	2011	2012	2011
	(Millions of Dollars, Except Per Share Amounts)			
Operating Revenues	$1,039.3	$1,052.8	$3,175.2	$3,373.2
Operating Expenses				
Fuel and purchased power	336.4	350.9	848.9	904.5
Cost of gas sold	55.5	69.2	368.0	533.4
Other operation and maintenance	244.6	296.9	798.8	909.3
Depreciation and amortization	91.8	82.6	269.7	246.2
Property and revenue taxes	30.4	28.9	90.9	85.5
Total Operating Expenses	758.7	828.5	2,376.3	2,678.9
Operating Income	280.6	224.3	798.9	694.3
Equity in Earnings of Transmission Affiliate	17.1	15.7	48.9	46.4
Other Income, net	9.0	16.2	33.6	43.1
Interest Expense, net	60.9	56.8	181.3	177.6
Income from Continuing Operations Before Income Taxes	245.8	199.4	700.1	606.2
Income Tax Expense	89.7	69.6	252.6	207.5
Income from Continuing Operations	156.1	129.8	447.5	398.7
Income from Discontinued Operations, Net of Tax	—	—	—	11.5
Net Income	$156.1	$129.8	$447.5	$410.2
Earnings Per Share (Basic)				
Continuing operations	$0.68	$0.56	$1.94	$1.71
Discontinued operations	—	—	—	0.05
Total Earnings Per Share (Basic)	$0.68	$0.56	$1.94	$1.76
Earnings Per Share (Diluted)				
Continuing operations	$0.67	$0.55	$1.92	$1.69
Discontinued operations	—	—	—	0.05
Total Earnings Per Share (Diluted)	$0.67	$0.55	$1.92	$1.74

Weighted Average Common Shares Outstanding (Millions)				
Basic	230.4	232.2	230.4	233.2
Diluted	232.9	234.9	233.1	236.0
Dividends Per Share of Common Stock	$0.30	$0.26	$0.90	$0.78

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

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WISCONSIN ENERGY CORPORATION
CONSOLIDATED CONDENSED BALANCE SHEETS
(Unaudited)

	September 30, 2012	December 31, 2011
	(Millions of Dollars)	
Assets		
Property, Plant and Equipment		
In service	$14,086.9	$12,977.7
Accumulated depreciation	(3,972.4)	(3,797.8)
	10,114.5	9,179.9
Construction work in progress	269.4	921.3
Leased facilities, net	54.9	59.2
Net Property, Plant and Equipment	10,438.8	10,160.4
Investments		
Equity investment in transmission affiliate	372.5	349.7
Other	36.4	43.6
Total Investments	408.9	393.3
Current Assets		
Cash and cash equivalents	13.0	14.1
Restricted cash	9.5	45.5
Accounts receivable, net	298.6	349.4
Income taxes receivable	48.4	155.1
Accrued revenues	178.5	252.7
Materials, supplies and inventories	342.1	382.0
Prepayments and other	194.7	227.4
Total Current Assets	1,084.8	1,426.2
Deferred Charges and Other Assets		
Regulatory assets	1,280.4	1,238.7
Goodwill	441.9	441.9
Other	179.9	201.6
Total Deferred Charges and Other Assets	1,902.2	1,882.2
Total Assets	$13,834.7	$13,862.1
Capitalization and Liabilities		
Capitalization		
Common equity	$4,147.2	$3,963.3
Preferred stock of subsidiary	30.4	30.4
Long-term debt	4,240.6	4,614.3
Total Capitalization	8,418.2	8,608.0
Current Liabilities		
Long-term debt due currently	381.1	32.6
Short-term debt	453.2	669.9
Accounts payable	277.7	325.7
Accrued payroll and benefits	101.5	105.9
Other	173.5	230.4
Total Current Liabilities	1,387.0	1,364.5
Deferred Credits and Other Liabilities		
Regulatory liabilities	872.9	902.0

Deferred income taxes - long-term	1,994.2	1,696.1
Deferred revenue, net	714.1	754.5
Pension and other benefit obligations	149.6	222.7
Other	298.7	314.3
Total Deferred Credits and Other Liabilities	4,029.5	3,889.6
Total Capitalization and Liabilities	$13,834.7	$13,862.1

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

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

	Nine Months Ended September 30	
	2012	2011
	(Millions of Dollars)	
Operating Activities		
Net income	$447.5	$410.2
Reconciliation to cash		
Depreciation and amortization	278.2	248.9
Deferred income taxes and investment tax credits, net	249.6	215.9
Contributions to qualified benefit plans	(100.0)	(257.4)
Change in - Accounts receivable and accrued revenues	118.7	136.4
Inventories	39.9	11.1
Other current assets	50.6	(18.7)
Accounts payable	(56.5)	(41.8)
Accrued income taxes, net	107.6	69.1
Other current liabilities	(15.3)	27.1
Other, net	(127.9)	26.8
Cash Provided by Operating Activities	992.4	827.6
Investing Activities		
Capital expenditures	(477.5)	(612.2)
Investment in transmission affiliate	(13.1)	(6.6)
Proceeds from asset sales	3.0	38.5
Change in restricted cash	36.0	(37.2)
Other, net	(39.8)	(32.8)
Cash Used in Investing Activities	(491.4)	(650.3)
Financing Activities		
Exercise of stock options	45.3	34.4
Purchase of common stock	(105.0)	(135.1)
Dividends paid on common stock	(207.4)	(182.0)
Issuance of long-term debt	—	720.0
Retirement and repurchase of long-term debt	(18.3)	(464.7)
Change in short-term debt	(216.7)	(161.2)
Other, net	—	1.9
Cash Used in Financing Activities	(502.1)	(186.7)
Change in Cash and Cash Equivalents	(1.1)	(9.4)
Cash and Cash Equivalents at Beginning of Period	14.1	24.5
Cash and Cash Equivalents at End of Period	$13.0	$15.1

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

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

1 -- GENERAL INFORMATION

Our accompanying unaudited consolidated condensed financial statements should be read in conjunction with Item 8, Financial Statements and Supplementary Data, in our 2011 Annual Report on Form 10-K. In the opinion of management, we have included all adjustments, normal and recurring in nature, necessary for a fair presentation of the results of operations, cash flows and financial position in the accompanying income statements, statements of cash flows and balance sheets. The results of operations for the three and nine months ended September 30, 2012 are not necessarily indicative of the results which may be expected for the entire fiscal year 2012 because of seasonal and other factors.

2 -- NEW ACCOUNTING PRONOUNCEMENTS

Presentation of Comprehensive Income: In June 2011, the Financial Accounting Standards Board (FASB) issued guidance on the presentation of comprehensive income. The guidance gives entities the option to present the total of comprehensive income, the components of net income and the components of other comprehensive income in either a single continuous statement of comprehensive income or in two separate but consecutive statements. This guidance is effective for fiscal years and interim periods beginning after December 15, 2011 and must be applied retrospectively. We adopted this guidance on January 1, 2012, and it did not have any material impact on us.

Fair Value Measurement: In May 2011, the FASB issued guidance amending existing guidance for measuring fair value and expanding required disclosures about fair value measurements. This guidance is effective for fiscal years and interim periods beginning after December 15, 2011 and must be applied prospectively. We adopted this guidance on January 1, 2012, and it did not have any material impact on us.

3 -- COMMON EQUITY

Stock Option Activity: During the first nine months of 2012, the Compensation Committee of the Board of Directors (Compensation Committee) granted 938,770 non-qualified stock options that had an estimated fair value of $3.34 per share. During the first nine months of 2011, the Compensation Committee granted 458,180 non-qualified stock options that had an estimated fair value of $3.17 per share. The following assumptions were used to value the options using a binomial option pricing model:

	2012		2011	
Risk-free interest rate	0.1% - 2.0%		0.2% - 3.4%	
Dividend yield	3.9	%	3.9	%
Expected volatility	19.0	%	19.0	%
Expected forfeiture rate	2.0	%	2.0	%
Expected life (years)	5.9		5.5	

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 nine months ended September 30, 2012:

Stock Options	Number of Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (Millions)
Outstanding as of July 1, 2012	9,571,531	$23.42		
Granted	—	$—		
Exercised	(370,020)	$17.89		
Forfeited	—	$—		
Outstanding as of September 30, 2012	9,201,511	$23.65		
Outstanding as of January 1, 2012	10,638,750	$21.65		
Granted	938,770	$34.88		
Exercised	(2,368,289)	$19.11		
Forfeited	(7,720)	$26.94		
Outstanding as of September 30, 2012	9,201,511	$23.65	5.4	$129.0
Exercisable as of September 30, 2012	7,493,036	$21.98	4.7	$117.6

The intrinsic value of options exercised was $8.3 million and $42.1 million for the three and nine months ended September 30, 2012, and $3.6 million and $22.6 million for the same periods in 2011, respectively. Cash received from options exercised was $45.3 million and $34.4 million for the nine months ended September 30, 2012 and 2011, respectively. The actual tax benefit realized for the tax deductions from option exercises for the same periods was zero and approximately $9.0 million, respectively.

All outstanding stock options to purchase shares of common stock were included in the computation of diluted earnings per share during the third quarter and first nine months of 2012.

The following table summarizes information about stock options outstanding as of September 30, 2012:

	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)
$12.71 to $19.74	1,874,519	$18.29	2.6	1,874,519	$18.29	2.6
$21.11 to $24.92	5,940,822	$23.13	5.5	5,491,282	$22.99	5.4
$29.35 to $34.88	1,386,170	$33.09	8.9	127,235	$32.67	8.9
	9,201,511	$23.65	5.4	7,493,036	$21.98	4.7

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The following table summarizes information about our non-vested options during the three and nine months ended September 30, 2012:

Non-Vested Stock Options	Number of Options	Weighted-Average Fair Value
Non-vested as of July 1, 2012	1,726,165	$3.31
Granted	—	$—
Vested	(17,690)	$3.31
Forfeited	—	$—
Non-vested as of September 30, 2012	1,708,475	$3.31
Non-vested as of January 1, 2012	3,103,770	$3.78
Granted	938,770	$3.34
Vested	(2,326,345)	$3.96
Forfeited	(7,720)	$3.25
Non-vested as of September 30, 2012	1,708,475	$3.31

As of September 30, 2012, total compensation costs related to non-vested stock options not yet recognized was approximately $1.7 million, which is expected to be recognized over the next 18 months on a weighted-average basis.

Restricted Shares: During the first nine months of 2012, the Compensation Committee granted 94,959 restricted shares to directors, officers and other key employees. These awards have a three-year vesting period, and generally, one-third of the award vests on each anniversary of the grant date. During the vesting period, restricted share recipients have voting rights and are entitled to dividends in the same manner as other shareholders.

The following restricted stock activity occurred during the three and nine months ended September 30, 2012:

Restricted Shares	Number of Shares	Weighted-Average Grant Date Fair Value
Outstanding as of July 1, 2012	194,697	
Granted	—	$—
Released	—	$—
Forfeited	(1,213)	$31.35
Outstanding as of September 30, 2012	193,484	
Outstanding as of January 1, 2012	192,558	
Granted	94,959	$34.46
Released	(88,422)	$30.65
Forfeited	(5,611)	$30.94
Outstanding as of September 30, 2012	193,484	

We record the market value of the restricted stock awards on the date of grant, and then we charge their value to expense over the vesting period of the awards. The intrinsic value of restricted stock vesting was zero and $3.3 million for the three and nine months ended September 30, 2012, and zero and $2.3 million for the same periods in 2011, respectively. The actual tax benefit realized for the tax deductions from released restricted shares was zero for the three and nine months ended September 30, 2012, and zero and $0.7 million for the same periods in 2011, respectively.

As of September 30, 2012, total compensation cost related to restricted stock not yet recognized was approximately $3.3 million, which is expected to be recognized over the next 22 months on a weighted-average basis.

Performance Units: In January 2012 and 2011, the Compensation Committee granted 346,570 and 435,690 performance units, respectively, to officers and other key employees under the Wisconsin Energy Performance Unit

Plan. Under the grants, the ultimate number of units that will be awarded is dependent upon the achievement of certain financial performance of our stock over a three-year period. Under the terms of the award, participants may earn between 0% and 175% of the base performance unit award. All grants are settled in cash. We are accruing compensation costs over the three-year period based on our estimate of the final expected value of the awards. Performance units earned as of December 31, 2011 and 2010 vested and were settled during the first quarter of 2012 and 2011, and had a total intrinsic value of $26.7 million and $12.6 million, respectively. The actual tax benefit realized for the tax deductions from the settlement of performance units was approximately $9.7 million and $4.3 million, respectively. As of September 30, 2012, total compensation cost related to performance units not yet recognized was approximately $18.4 million, which is expected to be recognized over the next 19 months on a weighted-average basis.

Restrictions: Wisconsin Energy's ability as a holding company to pay common dividends primarily depends on the availability of funds received from its non-utility subsidiary, We Power, and its utility subsidiaries. Various financing arrangements and regulatory requirements impose certain restrictions on the ability of our subsidiaries to transfer funds to us in the form of cash dividends, loans or advances. In addition, under Wisconsin law, Wisconsin Electric and Wisconsin Gas are prohibited from loaning funds, either directly or indirectly, to Wisconsin Energy. See Note I -- Common Equity in our 2011 Annual Report on Form 10-K for additional information on these and other restrictions.

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

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

There was no material other comprehensive income for the three and nine months ended September 30, 2012 or 2011.

Share Repurchase Program: In May 2011, our Board of Directors authorized a share repurchase program that allows us to repurchase up to $300 million of our common stock through the end of 2013. Through September 30, 2012, we have repurchased $114.0 million of our common stock pursuant to this program at an average cost of $31.45 per share. The share repurchase program does not obligate Wisconsin Energy to acquire any specific number of shares and may be suspended or terminated by the Board of Directors at any time. In addition, through our independent agents, we purchase shares on the open market to fulfill exercised stock options and restricted stock awards. The following table identifies the shares purchased by the Company in the following periods:

	Nine Months Ended September 30			
	2012		2011	
	Shares	Cost	Shares	Cost
	(In Millions)			
Under May 2011 share repurchase program	0.4	$14.0	2.5	$75.0
To fulfill exercised stock options and restricted stock awards	2.5	91.0	1.9	60.1
Total	2.9	$105.0	4.4	$135.1

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4 -- ASSET SALES, DIVESTITURES AND DISCONTINUED OPERATIONS

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

	Three Months Ended September 30		Nine Months Ended September 30	
	2012	2011	2012	2011
	(Millions of Dollars)			
Income from Continuing Operations	$156.1	$129.8	$447.5	$398.7
Income from Discontinued Operations, Net of Tax (a)	—	—	—	11.5
Net Income	$156.1	$129.8	$447.5	$410.2

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

Edgewater Generating Unit 5: On March 1, 2011, we sold our 25% interest in Edgewater Generating Unit 5 to Wisconsin Power and Light Company, a subsidiary of Alliant Energy Corp. (WPL) for our net book value, including working capital, of approximately $38 million. This transaction was treated as a sale of an asset.

5 -- LONG-TERM DEBT

In September 2011, Wisconsin Electric issued $300 million of 2.95% Debentures due September 15, 2021. The debentures were issued under an existing shelf registration statement filed with the SEC in February 2011. The net proceeds were used to repay short-term debt and for other general corporate purposes.

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

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

As of September 30, 2012, we were in compliance with all financial covenants.

6 -- FAIR VALUE MEASUREMENTS

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

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

Assets and liabilities measured and reported at fair value are classified and disclosed in one of the following categories:

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Level 1 -- Pricing inputs are unadjusted quoted prices available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Instruments in this category consist of financial instruments such as exchange-traded derivatives, cash equivalents and restricted cash investments.

Level 2 -- Pricing inputs are other than quoted prices in active markets, which are either directly or indirectly observable as of the reporting date, and fair value is determined through the use of models or other valuation methodologies. Instruments in this category include non-exchange-traded derivatives such as Over-the-Counter (OTC) forwards and options.

Level 3 -- Pricing inputs include significant inputs that are generally less observable from objective sources. The inputs in the determination of fair value require significant management judgment or estimation. At each balance sheet date, we perform an analysis of all instruments subject to fair value reporting and include in Level 3 all instruments whose fair value is based on significant unobservable inputs.

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

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

Recurring Fair Value Measures	As of September 30, 2012			
	Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Assets:				
Restricted Cash	$9.5	$—	$—	$9.5
Derivatives	11.0	12.9	7.3	31.2
Total	$20.5	$12.9	$7.3	$40.7
Liabilities:				
Derivatives	$—	$2.1	$—	$2.1
Total	$—	$2.1	$—	$2.1

Recurring Fair Value Measures	As of December 31, 2011			
	Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Assets:				
Restricted Cash	$45.5	$—	$—	$45.5
Derivatives	0.3	14.6	5.7	20.6
Total	$45.8	$14.6	$5.7	$66.1
Liabilities:				
Derivatives	$8.2	$1.0	$—	$9.2
Total	$8.2	$1.0	$—	$9.2

Restricted cash consists of certificates of deposit and government backed interest bearing securities and represents the settlement we received from the United States Department of Energy (DOE) during the first quarter of 2011, which is being returned, net of costs incurred, to customers. Derivatives reflect positions we hold in exchange-traded derivative contracts and OTC derivative contracts. Exchange-traded derivative contracts, which include futures and exchange-traded options, are generally based on unadjusted quoted prices in active markets and are classified within

Level 1. Some OTC derivative contracts are valued using broker or dealer quotations, or market transactions in either the listed or OTC markets utilizing a mid-market pricing convention (the mid-point between bid and ask prices), as appropriate. In such cases, these derivatives are classified within Level 2. Certain OTC derivatives may utilize models to measure fair value. Generally, we use a similar model to value similar instruments. Valuation models utilize various inputs which include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, other observable inputs for the asset or liability, and market-corroborated inputs (i.e., inputs derived principally from or corroborated by observable market data by correlation or other means). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. Certain OTC derivatives are in less active markets with a lower availability of pricing information which might not be observable in or corroborated by the market. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized in Level 3.

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

	Three Months Ended September 30		Nine Months Ended September 30	
	2012	2011	2012	2011
	(Millions of Dollars)			
Beginning Balance	$9.9	$14.6	$5.7	$5.9
Realized and unrealized gains (losses)	—	—	—	—
Purchases	—	—	10.9	16.1
Issuances	—	—	—	—
Settlements	(2.6)	(4.5)	(9.3)	(11.9)
Transfers in and/or out of Level 3	—	—	—	—
Balance as of September 30	$7.3	$10.1	$7.3	$10.1
Change in unrealized gains (losses) relating to instruments still held as of September 30	$—	$—	$—	$—

Derivative instruments reflected in Level 3 of the hierarchy include MISO Financial Transmission Rights (FTRs) that are measured at fair value each reporting period using monthly or annual auction shadow prices from relevant auctions. Changes in fair value for Level 3 recurring items are recorded on our balance sheet. See Note 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:

Financial Instruments	September 30, 2012 Carrying Amount	Fair Value	December 31, 2011 Carrying Amount	Fair Value
	(Millions of Dollars)			
Preferred stock, no redemption required	$30.4	$26.3	$30.4	$25.1
Long-term debt, including current portion	$4,523.2	$5,256.8	$4,541.4	$5,179.9

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 on debt, is estimated based upon quoted market value for the same or similar issues or upon the quoted market prices of U.S. Treasury issues having a similar term to maturity, adjusted for the issuing company's bond rating and the present value of future cash flows. Based on these assessments, the above items have been classified within Level 2.

7 -- DERIVATIVE INSTRUMENTS

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

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We record derivative instruments on the balance sheet as an asset or liability measured at its fair value, and changes in the derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are met or we receive regulatory treatment for the derivative. For most energy related physical and financial contracts in our regulated operations that qualify as derivatives, the PSCW allows the effects of the fair market value accounting to be offset to regulatory assets and liabilities. We do not offset fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral against fair value amounts recognized for derivatives executed with the same counterparty under the same master netting arrangement. As of September 30, 2012, we recognized $3.0 million in regulatory assets and $23.0 million in regulatory liabilities related to derivatives in comparison to $29.6 million in regulatory assets and $21.7 million in regulatory liabilities as of December 31, 2011.

We record our current derivative assets on the balance sheet in prepayments and other current assets and the current portion of the liabilities in other current liabilities. The long-term portion of our derivative assets of $1.6 million is recorded in other deferred charges and other assets as of September 30, 2012, and the long-term portion of our derivative liabilities of $0.2 million is recorded in other deferred credits and other liabilities as of September 30, 2012. Our Consolidated Condensed Balance Sheets as of September 30, 2012 and December 31, 2011 include:

	September 30, 2012		December 31, 2011	
	Derivative Asset	Derivative Liability	Derivative Asset	Derivative Liability
	(Millions of Dollars)			
Natural Gas	$12.0	$—	$2.1	$9.1
Fuel Oil	0.9	—	0.3	0.1
FTRs	7.3	—	5.7	—
Coal	11.0	2.1	12.5	—
Total	$31.2	$2.1	$20.6	$9.2

Our Consolidated Condensed Income Statements include gains (losses) on derivative instruments used in our risk management strategies under fuel and purchased power for those commodities supporting our electric operations and under cost of gas sold for the natural gas sold to our customers. Our estimated notional volumes and gains (losses) were as follows:

	Three Months Ended September 30, 2012		Three Months Ended September 30, 2011	
	Volume	Gains (Losses) (Millions of Dollars)	Volume	Gains (Losses) (Millions of Dollars)
Natural Gas	17.2 million Dth	$(5.3)	15.7 million Dth	$(10.5)
Fuel Oil	1.7 million gallons	0.1	2.2 million gallons	2.4
FTRs	5,927 MW	2.9	5,896 MW	5.2
Total		$(2.3)		$(2.9)

	Nine Months Ended September 30, 2012		Nine Months Ended September 30, 2011	
	Volume	Gains (Losses) (Millions of Dollars)	Volume	Gains (Losses) (Millions of Dollars)
Natural Gas	56.0 million Dth	$(35.7)	54.0 million Dth	$(27.7)
Fuel Oil	5.5 million gallons	1.5	8.8 million gallons	4.9
FTRs	16,581 MW	5.1	18,439 MW	10.5

Total	$(29.1)	$(12.3)

As of September 30, 2012 and December 31, 2011, we posted collateral of $0.4 million and $11.9 million, respectively, in our margin accounts. These amounts are recorded on the balance sheets in other current assets.

8 -- BENEFITS

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

	Pension Costs			
	Three Months Ended September 30		Nine Months Ended September 30	
Benefit Plan Cost Components	2012	2011	2012	2011
	(Millions of Dollars)			
Net Periodic Benefit Cost				
Service cost	$5.5	$4.0	$16.3	$11.9
Interest cost	16.4	16.9	49.2	50.7
Expected return on plan assets	(22.5)	(20.5)	(67.3)	(61.6)
Amortization of:				
Prior service cost	0.5	0.6	1.7	1.7
Actuarial loss	10.2	8.4	30.4	25.5
Net Periodic Benefit Cost	$10.1	$9.4	$30.3	$28.2

	OPEB Costs			
	Three Months Ended September 30		Nine Months Ended September 30	
Benefit Plan Cost Components	2012	2011	2012	2011
	(Millions of Dollars)			
Net Periodic Benefit Cost				
Service cost	$2.6	$2.6	$7.8	$7.8
Interest cost	5.1	5.2	15.3	15.6
Expected return on plan assets	(4.8)	(4.3)	(14.4)	(12.7)
Amortization of:				
Transition obligation	—	—	0.2	0.2
Prior service (credit)	(0.5)	(0.4)	(1.4)	(1.4)
Actuarial loss	1.9	1.7	5.4	4.7
Net Periodic Benefit Cost	$4.3	$4.8	$12.9	$14.2

During the first nine months of 2012 and 2011, we contributed $100.0 million and $257.4 million, respectively, to our qualified benefit plans. Future contributions to the plans will be dependent upon many factors, including the performance of existing plan assets and long-term discount rates.

Postemployment Benefits: Postemployment benefits provided to former or inactive employees are recognized when an event occurs. The estimated liability for such benefits was $5.2 million as of September 30, 2012 and $15.3 million as of December 31, 2011.

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9 -- SEGMENT INFORMATION

Summarized financial information concerning our reportable segments for the three and nine months ended September 30, 2012 and 2011 is shown in the following table:

Three Months Ended	Reportable Segments Energy Utility	Non-Utility	Corporate & Other (a)	Eliminations & Reconciling Items	Total Consolidated
	(Millions of Dollars)				
September 30, 2012					
Operating Revenues (b)	$1,023.3	$112.6	$0.3	$(96.9)	$1,039.3
Other Operation and Maintenance	$334.1	$4.3	$2.0	$(95.8)	$244.6
Depreciation and Amortization	$74.7	$16.8	$0.3	$—	$91.8
Operating Income (Loss)	$191.0	$91.5	$(1.9)	$—	$280.6
Equity in Earnings of Unconsolidated Affiliates	$17.1	$—	$—	$—	$17.1
Interest Expense, Net	$31.4	$16.6	$12.9	$—	$60.9
Income Tax Expense (Benefit)	$65.6	$29.2	$(5.1)	$—	$89.7
Income from Discontinued Operations, Net of Tax	$—	$—	$—	$—	$—
Net Income (Loss)	$119.8	$45.8	$156.1	$(165.6)	$156.1
Capital Expenditures	$161.2	$1.8	$0.5	$—	$163.5
September 30, 2011					
Operating Revenues (b)	$1,036.7	$113.0	$0.2	$(97.1)	$1,052.8
Other Operation and Maintenance	$387.0	$4.9	$1.0	$(96.0)	$296.9
Depreciation and Amortization	$64.1	$18.3	$0.2	$—	$82.6
Operating Income (Loss)	$135.6	$89.8	$(1.1)	$—	$224.3
Equity in Earnings of Unconsolidated Affiliates	$15.7	$—	$(0.1)	$—	$15.6
Interest Expense, Net	$26.8	$16.9	$13.2	$(0.1)	$56.8
Income Tax Expense (Benefit)	$45.5	$28.4	$(4.3)	$—	$69.6
Income from Discontinued Operations, Net of Tax	$—	$—	$—	$—	$—
Net Income (Loss)	$95.0	$44.6	$129.7	$(139.5)	$129.8
Capital Expenditures	$252.1	$7.3	$5.7	$—	$265.1

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Nine Months Ended	Reportable Segments Energy Utility	Non-Utility	Corporate & Other (a)	Eliminations & Reconciling Items	Total Consolidated
	(Millions of Dollars)				
September 30, 2012					
Operating Revenues (b)	$3,132.2	$332.2	$0.9	$(290.1)	$3,175.2
Other Operation and Maintenance	$1,069.0	$11.7	$4.7	$(286.6)	$798.8
Depreciation and Amortization	$218.8	$50.3	$0.6	$—	$269.7
Operating Income (Loss)	$533.2	$270.2	$(4.5)	$—	$798.9
Equity in Earnings of Unconsolidated Affiliates	$48.9	$—	$(0.1)	$—	$48.8
Interest Expense, Net	$92.6	$50.1	$38.9	$(0.3)	$181.3
Income Tax Expense (Benefit)	$182.6	$87.2	$(17.2)	$—	$252.6
Income from Discontinued Operations, Net of Tax	$—	$—	$—	$—	$—
Net Income (Loss)	$338.7	$133.2	$448.0	$(472.4)	$447.5
Capital Expenditures	$468.2	$5.6	$3.7	$—	$477.5
September 30, 2011					
Operating Revenues (b)	$3,331.1	$327.5	$0.6	$(286.0)	$3,373.2
Other Operation and Maintenance	$1,176.7	$11.5	$3.8	$(282.7)	$909.3
Depreciation and Amortization	$191.4	$54.3	$0.5	$—	$246.2
Operating Income (Loss)	$436.7	$261.7	$(4.1)	$—	$694.3
Equity in Earnings of Unconsolidated Affiliates	$46.4	$—	$(0.3)	$—	$46.1
Interest Expense, Net	$82.1	$49.8	$46.0	$(0.3)	$177.6
Income Tax Expense (Benefit)	$145.9	$84.2	$(22.6)	$—	$207.5
Income from Discontinued Operations, Net of Tax	$—	$—	$11.5	$—	$11.5
Net Income (Loss)	$297.1	$127.9	$410.0	$(424.8)	$410.2
Capital Expenditures	$583.1	$22.2	$6.9	$—	$612.2

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

(b) An elimination for intersegment revenues is included in Operating Revenues. This elimination is primarily between We Power and Wisconsin Electric.

10 -- VARIABLE INTEREST ENTITIES

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

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

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

We also have a purchased power agreement for 236 MW of firm capacity from a gas-fired cogeneration facility, which we account for as a capital lease. The agreement includes no minimum energy requirements over the remaining term of approximately 10 years. We have examined the risks of the entity including operations and maintenance, dispatch, financing, fuel costs and other factors, and have determined that we are not the primary beneficiary of the entity. We do not hold an equity or debt interest in the entity and there is no residual guarantee associated with the purchased power agreement.

We have approximately $270.2 million of required payments over the remaining term of these agreements. We believe that the required lease payments under these contracts will continue to be recoverable in rates. Total capacity and lease payments under these contracts for the nine months ended September 30, 2012 and 2011 were $44.5 million and $51.0 million, respectively. Our maximum exposure to loss is limited to the capacity payments under the contracts.

11 -- COMMITMENTS AND CONTINGENCIES

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

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

Manufactured Gas Plant Sites: We have identified several sites at which Wisconsin Electric, Wisconsin Gas, or a predecessor company historically owned or operated a manufactured gas plant. These sites have been substantially remediated or are at various stages of investigation, monitoring and remediation. We have also identified other sites that may have been impacted by historical manufactured gas plant activities. Based upon on-going analysis, we estimate that the future costs for detailed site investigation and future remediation costs may range from $21 million to $65 million over the next ten years. This estimate is dependent upon several variables including, among other things, the extent of remediation, changes in technology and changes in regulation. As of September 30, 2012, we have established reserves of $37.5 million related to future remediation costs.

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

Valley Power Plant Title V Air Permit: The WDNR renewed Valley Power Plant's (VAPP) Title V operating permit in February 2011. The term of the permit is five years. Sierra Club and Clean Wisconsin requested and were granted an administrative hearing before the WDNR on certain conditions of the permit. The case has been stayed. In March 2011, the Sierra Club also petitioned the United States Environmental Protection Agency (EPA) for additional reductions and monitoring for particulate matter, and revisions to certain applicable requirements. No timeline has been set by the EPA to respond to that petition. In May 2012, the Sierra Club filed a notice of intent to bring suit to force the EPA to issue a response to that petition.

We believe that the permit was properly issued and that the plant is in compliance with all applicable regulations and standards. However, if as a result of either proceeding the permit is remanded to the WDNR, the plant will continue to operate under the previous operating permit.

We have made significant progress on the four voluntary goals we submitted in a December 2011 letter to the EPA. Through the end of the third quarter: (1) we achieved reductions in annual Sulfur Dioxide (SO_2) emissions from the plant to no more than 4,500 tons (a 65% decrease from 2001 emission levels); (2) the planned conversion of the plant from coal to natural gas would eliminate the requirement to meet the Mercury and Air Toxics Standards (MATS) rules and, therefore, the need for a dry sorbent injection system; (3) we held open houses and tours of VAPP to help inform the community on the plant, the unique role that it plays in the community, and to share environmental successes and future plans; and (4) we announced plans for converting VAPP to natural gas fuel by the end of 2015, provided that we can obtain authorization from the PSCW to do so.

Divested Assets: Pursuant to the sale of the Point Beach Nuclear Power Plant (Point Beach), we have agreed to indemnification provisions customary to transactions involving the sale of nuclear assets. We also provided customary indemnifications to WPL in connection with the sale of our interest in Edgewater Generating Unit 5.

Cash Balance Pension Plan: In June 2009, a lawsuit was filed by Alan M. Downes, a former employee, against the Wisconsin Energy Corporation Retirement Account Plan (Plan) in the U.S. District Court for the Eastern District of Wisconsin. The complaint alleged that Plan participants who received a lump sum distribution under the Plan prior to their normal retirement age did not receive the full benefit to which they were entitled in violation of the Employee Retirement Income Security Act of 1974 (ERISA) and were owed additional benefits, because the Plan failed to apply the correct interest crediting rate to project the cash balance account to their normal retirement age. In September 2010, the plaintiff filed a First Amended Class Action Complaint alleging additional claims under ERISA and adding Wisconsin Energy as a defendant.

In November 2011, we entered into a settlement agreement with the plaintiffs for $45.0 million, and the court promptly issued an order preliminarily approving the settlement. As part of the settlement agreement, we agreed to class certification for all similarly situated plaintiffs. The resolution of this matter resulted in a cost of less than $0.04 per share for 2011 after considering insurance and reserves established in the prior year. The court approved the settlement on April 3, 2012 and issued its written order on April 20, 2012. Substantially all payments to class members have been made pursuant to the settlement. We do not anticipate further charges as a result of the settlement.

Income Taxes: During the first quarter of 2012, the IRS issued guidance applicable to taxpayers that have taken positions within prior year tax returns relating to the conversion of capitalized assets to repair expense. As a result of this guidance, we have decreased our unrecognized tax benefits by approximately $7.4 million, exclusive of accrued interest.

12 -- SUPPLEMENTAL CASH FLOW INFORMATION

During the nine months ended September 30, 2012, we paid $137.9 million in interest, net of amounts capitalized, and received $107.0 million in net refunds from income taxes. During the nine months ended September 30, 2011, we paid $138.1 million in interest, net of amounts capitalized, and received $62.7 million in net refunds from income taxes.

As of September 30, 2012 and 2011, the amount of accounts payable related to capital expenditures was $25.3 million and $19.2 million, respectively.

During the nine months ended September 30, 2012 and 2011, total amortization of deferred revenue was $41.2 million and $40.7 million, respectively.

During the nine months ended September 30, 2012 and 2011, our equity in earnings from ATC was $48.9 million and $46.4 million, respectively. During the nine months ended September 30, 2012 and 2011, distributions received from ATC were $39.0 million and $37.0 million, respectively.

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

RESULTS OF OPERATIONS -- THREE MONTHS ENDED SEPTEMBER 30, 2012

CONSOLIDATED EARNINGS

The following table compares our operating income by business segment and our net income during the third quarter of 2012 with the third quarter of 2011, including favorable (better (B)) or unfavorable (worse (W)) variances:

	Three Months Ended September 30		
	2012	B (W)	2011
	(Millions of Dollars)		
Utility Energy Segment	$191.0	$55.4	$135.6
Non-Utility Energy Segment	91.5	1.7	89.8
Corporate and Other	(1.9)	(0.8)	(1.1)
Total Operating Income	280.6	56.3	224.3
Equity in Earnings of Transmission Affiliate	17.1	1.4	15.7
Other Income, net	9.0	(7.2)	16.2
Interest Expense, net	60.9	(4.1)	56.8
Income from Continuing Operations Before Income Taxes	245.8	46.4	199.4
Income Tax Expense	89.7	(20.1)	69.6
Income from Continuing Operations	$156.1	$26.3	$129.8
Diluted Earnings Per Share from Continuing Operations	$0.67	$0.12	$0.55

UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

Our utility energy segment contributed $191.0 million of operating income during the third quarter of 2012, an increase of $55.4 million, or 40.9%, compared with the third quarter of 2011. The following table summarizes the operating income of this segment between the comparative quarters:

	Three Months Ended September 30		
Utility Energy Segment	2012	B (W)	2011
	(Millions of Dollars)		
Operating Revenues			
Electric	$901.2	$1.0	$900.2
Gas	116.7	(13.6)	130.3
Other	5.4	(0.8)	6.2
Total Operating Revenues	1,023.3	(13.4)	1,036.7
Operating Expenses			
Fuel and Purchased Power	337.7	14.4	352.1
Cost of Gas Sold	55.5	13.7	69.2
Other Operation and Maintenance	334.1	52.9	387.0
Depreciation and Amortization	74.7	(10.6)	64.1

Property and Revenue Taxes	30.3	(1.6)	28.7
Total Operating Expenses	832.3	68.8	901.1
Operating Income	$191.0	$55.4	$135.6

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Electric Utility Revenues and Sales

The following table compares electric utility operating revenues and MWh sales by customer class during the third quarter of 2012 with the third quarter of 2011:

	Three Months Ended September 30					
	Electric Revenues			MWh Sales		
Electric Utility Operations	2012	B (W)	2011	2012	B (W)	2011
	(Millions of Dollars)			(Thousands)		
Customer Class						
Residential	$340.2	$0.4	$339.8	2,422.5	(28.6)	2,451.1
Small Commercial/Industrial	284.2	5.2	279.0	2,456.3	16.6	2,439.7
Large Commercial/Industrial	200.7	(8.9)	209.6	2,486.1	(225.5)	2,711.6
Other - Retail	5.4	0.1	5.3	34.6	(1.1)	35.7
Total Retail	830.5	(3.2)	833.7	7,399.5	(238.6)	7,638.1
Wholesale - Other	40.0	1.5	38.5	411.7	(76.2)	487.9
Resale - Utilities	17.8	(3.1)	20.9	596.3	70.9	525.4
Other Operating Revenues	12.9	5.8	7.1	—	—	—
Total	$901.2	$1.0	$900.2	8,407.5	(243.9)	8,651.4
Weather -- Degree Days (a)						
Heating (126 Normal)				138	(18)	156
Cooling (526 Normal)				735	62	673

(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 $1.0 million, or 0.1%, when compared to the third quarter of 2011.

We estimate favorable summer weather increased revenues by approximately $31 million in our Residential and Small Commercial/Industrial customer classes in 2012 compared to normal weather conditions. By comparison, we estimate that favorable weather in 2011 increased revenues for these customer classes by approximately $28 million compared to normal weather conditions.

Sales to the Large Commercial/Industrial customer class decreased by 8.3% in 2012 compared to 2011. Large Commercial/Industrial revenues decreased by approximately $8.9 million compared to 2011. We estimate that our revenues were reduced by approximately $15 million because of the planned outage at an iron ore mine of our largest customer, and the conversion to self-generation of two other large customers. If sales to the mines and the two customers that added self-generation are excluded, our MWh sales to Large Commercial/Industrial customers increased by 0.6%.

In addition, our retail revenues increased by approximately $13 million in 2012 because of rate increases in Michigan and favorable fuel recoveries in Wisconsin. Other Operating Revenues increased by approximately $5.8 million driven by the $8 million of amortization related to the DOE settlement used to offset an increase in fuel costs authorized by the PSCW. For additional information on the 2012 Michigan rate case and the DOE settlement, see Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters and -- Nuclear Operations, respectively.

Fuel and Purchased Power

Our fuel and purchased power costs decreased by $14.4 million, or 4.1%, when compared to the third quarter of 2011. This decrease was primarily caused by a 2.8% decrease in total MWh sales and a reduction in our average cost of fuel and purchased power because of lower natural gas prices.

Gas Utility Revenues, Gross Margin and Therm Deliveries

A comparison follows of gas utility operating revenues, gross margin and gas deliveries during the third quarter of 2012 with the third quarter of 2011. 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 $13.6 million, or 10.4%, and cost of gas sold decreased by $13.7 million, or 19.8%.

	Three Months Ended September 30		
	2012	B (W)	2011
	(Millions of Dollars)		
Gas Operating Revenues	$116.7	$(13.6)	$130.3
Cost of Gas Sold	55.5	13.7	69.2
Gross Margin	$61.2	$0.1	$61.1

The following table compares gas utility gross margin and natural gas therm deliveries by customer class during the third quarter of 2012 with the third quarter of 2011:

	Three Months Ended September 30					
	Gross Margin			Therm Deliveries		
Gas Utility Operations	2012	B (W)	2011	2012	B (W)	2011
	(Millions of Dollars)			(Millions)		
Customer Class						
Residential	$37.9	$(0.3)	$38.2	46.2	(2.1)	48.3
Commercial/Industrial	10.2	(0.1)	10.3	33.1	(0.2)	33.3
Interruptible	0.3	—	0.3	2.3	—	2.3
Total Retail	48.4	(0.4)	48.8	81.6	(2.3)	83.9
Transported Gas	11.8	0.7	11.1	269.7	69.4	200.3
Other	1.0	(0.2)	1.2	—	—	—
Total	$61.2	$0.1	$61.1	351.3	67.1	284.2
Weather -- Degree Days (a)						
Heating (126 Normal)				138	(18)	156

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

Our gas margin is seasonal and is primarily driven by the heating needs of our customers. The third quarter gas margin is historically the lowest of the year because of the lack of heating load. Our gas margin increased by $0.1 million, or approximately 0.2%, when compared to the third quarter of 2011.

Other Operation and Maintenance Expense

Our other operation and maintenance expense decreased by $52.9 million, or approximately 13.7%, when compared to the third quarter of 2011. This decrease, which we expect to continue through the remainder of the year, is primarily due to the one year suspension of $148 million of amortization expense on certain regulatory assets as authorized under our 2012 Wisconsin Rate Case. For additional information on the 2012 rate case, see Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters.

Depreciation and Amortization Expense

Our depreciation and amortization expense increased by $10.6 million, or approximately 16.5%, when compared to the third quarter of 2011 primarily because of an overall increase in utility plant in service. The Glacier Hills Wind Park went into service in December 2011. In addition, the emission control equipment for units 5 and 6 of the Oak

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Creek Air Quality Control System (AQCS) project went into service in March 2012, and for units 7 and 8 in September 2012. For additional information, see Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters -- Oak Creek Air Quality Control System.

NON-UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

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

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

	Three Months Ended September 30		
	2012	B (W)	2011
	(Millions of Dollars)		
Operating Revenues	$112.6	$(0.4)	$113.0
Operation and Maintenance Expense	4.3	0.6	4.9
Depreciation Expense	16.8	1.5	18.3
Operating Income	$91.5	$1.7	$89.8

CONSOLIDATED OTHER INCOME, NET

	Three Months Ended September 30		
	2012	B (W)	2011
	(Millions of Dollars)		
AFUDC - Equity	$8.9	$(7.1)	$16.0
Other, net	0.1	(0.1)	0.2
Other Income, net	$9.0	$(7.2)	$16.2

Other income, net decreased by $7.2 million, or approximately 44.4%, when compared to the third quarter of 2011. The decrease in AFUDC - Equity is primarily related to the Glacier Hills Wind Park, which went into service in December 2011, as well as the Oak Creek AQCS project which emission control equipment went into service in March 2012 for units 5 and 6 and September 2012 for units 7 and 8. For additional information, see Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters -- Oak Creek Air Quality Control System.

CONSOLIDATED INTEREST EXPENSE, NET

	Three Months Ended September 30		
	2012	B (W)	2011
	(Millions of Dollars)		
Gross Interest Costs	$65.0	$(1.3)	$63.7

Less: Capitalized Interest	4.1	(2.8)	6.9
Interest Expense, net	$60.9	$(4.1)	$56.8

Our gross interest costs increased by $1.3 million, or approximately 2.0%, when compared to the third quarter of 2011 primarily because of the issuance of $300 million of long-term debt by Wisconsin Electric in September 2011.

Our capitalized interest decreased by $2.8 million primarily because of lower construction work in progress. As a result, our net interest expense increased by $4.1 million, or 7.2%, as compared to the third quarter of 2011.

CONSOLIDATED INCOME TAX EXPENSE

For the third quarter of 2012, our effective tax rate applicable to continuing operations was 36.5% compared to 34.9% for the third quarter of 2011, primarily due to a decrease in the projected 2012 annual tax benefits associated with AFUDC - Equity. For additional information, see Note H -- Income Taxes in our 2011 Annual Report on Form 10-K.

RESULTS OF OPERATIONS -- NINE MONTHS ENDED SEPTEMBER 30, 2012

CONSOLIDATED EARNINGS

The following table compares our operating income by business segment and our net income during the first nine months of 2012 with the first nine months of 2011, including favorable (better (B)) or unfavorable (worse (W)) variances:

	Nine Months Ended September 30		
	2012	B (W)	2011
	(Millions of Dollars)		
Utility Energy Segment	$533.2	$96.5	$436.7
Non-Utility Energy Segment	270.2	8.5	261.7
Corporate and Other	(4.5)	(0.4)	(4.1)
Total Operating Income	798.9	104.6	694.3
Equity in Earnings of Transmission Affiliate	48.9	2.5	46.4
Other Income, net	33.6	(9.5)	43.1
Interest Expense, net	181.3	(3.7)	177.6
Income from Continuing Operations Before Income Taxes	700.1	93.9	606.2
Income Tax Expense	252.6	(45.1)	207.5
Income from Continuing Operations	$447.5	$48.8	$398.7
Diluted Earnings Per Share from Continuing Operations	$1.92	$0.23	$1.69
Diluted Earnings Per Share from Discontinued Operations	$—	$(0.05)	$0.05

UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

Our utility energy segment contributed $533.2 million of operating income during the first nine months of 2012, an increase of $96.5 million, or 22.1%, compared with the first nine months of 2011. The following table summarizes the operating income of this segment between the comparative periods:

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Utility Energy Segment	Nine Months Ended September 30 2012	B (W)	2011
	(Millions of Dollars)		
Operating Revenues			
Electric	$2,451.1	$11.7	$2,439.4
Gas	656.3	(206.5)	862.8
Other	24.8	(4.1)	28.9
Total Operating Revenues	3,132.2	(198.9)	3,331.1
Operating Expenses			
Fuel and Purchased Power	852.8	55.3	908.1
Cost of Gas Sold	368.0	165.4	533.4
Other Operation and Maintenance	1,069.0	107.7	1,176.7
Depreciation and Amortization	218.8	(27.4)	191.4
Property and Revenue Taxes	90.4	(5.6)	84.8
Total Operating Expenses	2,599.0	295.4	2,894.4
Operating Income	$533.2	$96.5	$436.7

Electric Utility Revenues and Sales

The following table compares electric utility operating revenues and MWh sales by customer class during the first nine months of 2012 with the first nine months of 2011:

	Nine Months Ended September 30					
	Electric Revenues			MWh Sales		
Electric Utility Operations	2012	B (W)	2011	2012	B (W)	2011
	(Millions of Dollars)			(Thousands)		
Customer Class						
Residential	$891.7	$9.1	$882.6	6,354.0	37.3	6,316.7
Small Commercial/Industrial	779.1	13.0	766.1	6,777.3	73.7	6,703.6
Large Commercial/Industrial	569.0	(12.6)	581.6	7,339.7	(247.7)	7,587.4
Other - Retail	16.6	—	16.6	111.2	0.6	110.6
Total Retail	2,256.4	9.5	2,246.9	20,582.2	(136.1)	20,718.3
Wholesale - Other	112.3	(2.1)	114.4	1,113.1	(379.7)	1,492.8
Resale - Utilities	43.2	(10.4)	53.6	1,392.1	(139.5)	1,531.6
Other Operating Revenues	39.2	14.7	24.5	—	—	—
Total	$2,451.1	$11.7	$2,439.4	23,087.4	(655.3)	23,742.7
Weather -- Degree Days (a)						
Heating (4,385 Normal)				3,513	(1,124)	4,637
Cooling (686 Normal)				1,041	255	786

(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 $11.7 million, or 0.5%, when compared to the first nine months of 2011.

We estimate favorable weather increased revenues by approximately $39 million in our Residential and Small Commercial/Industrial customer classes in 2012 compared to normal weather conditions. By comparison, we estimate that favorable weather in 2011 increased revenues for these customer classes by approximately $23 million compared to normal weather conditions.

Sales to the Large Commercial/Industrial customer class decreased by 3.3% in 2012 compared to 2011. Large Commercial/Industrial revenues decreased by approximately $12.6 million compared to 2011. We estimate that our revenues were reduced by approximately $23 million because of the planned outage at an iron ore mine of our largest customer, and the conversion to self-generation of two other large customers. If sales to the mines and the two customers that added self-generation are excluded, our MWh sales to Large Commercial/Industrial customers increased by 1.7%.

In addition, our retail revenues increased by approximately $9 million in 2012 because of rate increases in Michigan and favorable fuel recoveries in Wisconsin. Other Operating Revenues increased by approximately $14.7 million driven by the $22 million of amortization related to the DOE settlement used to offset an increase in fuel costs authorized by the PSCW.

Fuel and Purchased Power

Our fuel and purchased power costs decreased by $55.3 million, or 6.1%, when compared to the first nine months of 2011. This decrease was primarily caused by a 2.8% decrease in total MWh sales and a reduction in our average cost of fuel and purchased power because of lower natural gas prices.

Gas Utility Revenues, Gross Margin and Therm Deliveries

A comparison follows of gas utility operating revenues, gross margin and gas deliveries during the first nine months of 2012 with the first nine months of 2011. 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 $206.5 million, or 23.9%, and cost of gas sold decreased by $165.4 million, or 31.0%, due to the significantly warmer weather, which resulted in lower therm deliveries, and a decline in the commodity cost of natural gas.

	Nine Months Ended September 30		
	2012	B (W)	2011
	(Millions of Dollars)		
Gas Operating Revenues	$656.3	$(206.5)	$862.8
Cost of Gas Sold	368.0	165.4	533.4
Gross Margin	$288.3	$(41.1)	$329.4

The following table compares gas utility gross margin and natural gas therm deliveries by customer class during the first nine months of 2012 with the first nine months of 2011:

	Nine Months Ended September 30					
	Gross Margin			Therm Deliveries		
Gas Utility Operations	2012	B (W)	2011	2012	B (W)	2011
	(Millions of Dollars)			(Millions)		
Customer Class						
Residential	$184.5	$(26.5)	$211.0	436.9	(119.1)	556.0
Commercial/Industrial	59.4	(13.4)	72.8	254.2	(73.0)	327.2
Interruptible	1.2	(0.2)	1.4	9.9	(1.9)	11.8
Total Retail	245.1	(40.1)	285.2	701.0	(194.0)	895.0
Transported Gas	38.6	(0.3)	38.9	876.9	209.5	667.4
Other	4.6	(0.7)	5.3	—	—	—
Total	$288.3	$(41.1)	$329.4	1,577.9	15.5	1,562.4

Weather -- Degree Days (a)			
Heating (4,385 Normal)	3,513	(1,124)	4,637

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

Our gas margin decreased by $41.1 million, or approximately 12.5%, when compared to the first nine months of 2011. This decrease primarily relates to a decrease in sales volumes as a result of warmer weather during the first nine months of 2012 that decreased heating loads. As measured by heating degree days, the first nine months of 2012 were 24.2% warmer than the same period in 2011 and 19.9% warmer than normal. Transported gas volumes for the first nine months of 2012 increased by 31.4% as compared to the same period in 2011. Virtually all of the volume increase related to gas used in electric generation, which has a small impact on margin. This margin increase was more than offset by a reduction in transportation volumes delivered to higher margin classes that are more weather sensitive than our large transport customers.

Other Operation and Maintenance Expense

Our other operation and maintenance expense decreased by $107.7 million, or approximately 9.2%, when compared to the first nine months of 2011, primarily due to the one year suspension of $148 million of amortization expense on certain regulatory assets as authorized under our 2012 Wisconsin Rate Case.

Depreciation and Amortization Expense

Our depreciation and amortization expense increased by $27.4 million, or approximately 14.3%, when compared to the first nine months of 2011 primarily because of an overall increase in utility plant in service. The Glacier Hills Wind Park went into service in December 2011. In addition, the emission control equipment for units 5 and 6 of the Oak Creek AQCS project went into service in March 2012, and for units 7 and 8 in September 2012.

NON-UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

The table below reflects nine months of earnings in 2012 and 2011 for PWGS 1, PWGS 2, OC 1 and the common facilities for the Oak Creek expansion. It also reflects nine months of earnings in 2012 and approximately eight and a half months of earnings in 2011 for OC 2. This segment reflects the lease revenues on the new units as well as the depreciation expense. The operating and maintenance costs associated with the plants are the responsibility of Wisconsin Electric and are recorded in the utility segment.

	Nine Months Ended September 30		
	2012	B (W)	2011
	(Millions of Dollars)		
Operating Revenues	$332.2	$4.7	$327.5
Operation and Maintenance Expense	11.7	(0.2)	11.5
Depreciation Expense	50.3	4.0	54.3
Operating Income (Loss)	$270.2	$8.5	$261.7

CONSOLIDATED OTHER INCOME, NET

	Nine Months Ended September 30		
	2012	B (W)	2011
	(Millions of Dollars)		
AFUDC - Equity	$31.7	$(9.9)	$41.6
Other, net	1.9	0.4	1.5

Other Income, net	$33.6	$(9.5)	$43.1

Other income, net decreased by $9.5 million, or approximately 22.0%, when compared to the first nine months of 2011. The decrease in AFUDC - Equity is primarily related to the Glacier Hills Wind Park, which went into service in December 2011, as well as the Oak Creek AQCS project which emission control equipment went into service in March 2012 for units 5 and 6 and September 2012 for units 7 and 8.

CONSOLIDATED INTEREST EXPENSE, NET

	Nine Months Ended September 30		
	2012	B (W)	2011
	(Millions of Dollars)		
Gross Interest Costs	$195.4	$1.3	$196.7
Less: Capitalized Interest	14.1	(5.0)	19.1
Interest Expense, net	$181.3	$(3.7)	$177.6

Our gross interest costs decreased by $1.3 million, or approximately 0.7%, when compared to the first nine months of 2011 primarily because we retired $450 million of long-term debt in April 2011. This decrease was partially offset by increased interest costs associated with the issuance of $300 million of long-term debt by Wisconsin Electric in September 2011. Our capitalized interest decreased by $5.0 million primarily because of lower construction work in progress. As a result, our net interest expense increased by $3.7 million, or 2.1%, as compared to the first nine months of 2011.

CONSOLIDATED INCOME TAX EXPENSE

For the first nine months of 2012, our effective tax rate applicable to continuing operations was 36.1% compared to 34.2% for the first nine months of 2011, primarily due to a decrease in the projected 2012 annual tax benefits associated with AFUDC - Equity. For additional information, see Note H -- Income Taxes in our 2011 Annual Report on Form 10-K. We expect our 2012 annual effective tax rate to be between 35.5% and 36.5%.

DISCONTINUED OPERATIONS

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

LIQUIDITY AND CAPITAL RESOURCES

CASH FLOWS

The following summarizes our cash flows from continuing operations during the nine months ended September 30:

	2012	2011
	(Millions of Dollars)	
Cash Provided by (Used in)		
Operating Activities	$992.4	$827.6
Investing Activities	$(491.4)	$(650.3)
Financing Activities	$(502.1)	$(186.7)

Operating Activities

Cash provided by operating activities increased by $164.8 million during the first nine months of 2012 as compared to the same period in 2011. Increases in cash provided by operating activities are attributed to higher net income, higher depreciation expense and lower contributions to our benefit plans. In September 2012, we contributed $100.0 million to our qualified benefits plans, compared to $257.4 million during the first nine months of 2011. In addition, our non-cash charges related to the amortization of certain regulatory assets and liabilities was $111.0 million lower in the first nine months of 2012 as compared to the first nine months in 2011 because the PSCW allowed us to suspend these amortizations in 2012.

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Investing Activities

Cash used in investing activities declined by $158.9 million during the first nine months of 2012