Wisconsin Energy Corporation

Standing the **Test of Time**

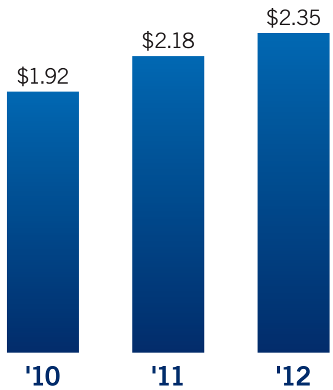
2012 Annual Report

"I want to reach out to the men and women and all the WEC families who sacrificed their time and expertise to meet the needs of the people of Long Island. My dad is age 87. He has been fighting colon cancer and is in grave condition. My siblings and I are so thankful to the great state of Wisconsin for these individuals who were so generous to help us. Please thank them from the bottom of my heart. I have campaigned for a 'hug a cheesehead today' on their behalf!"

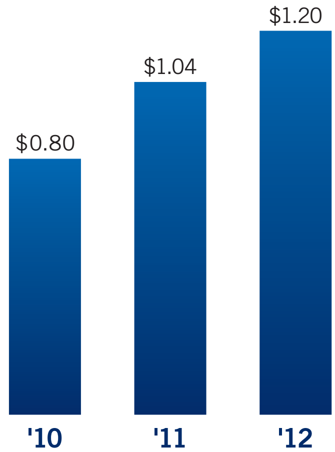
When Superstorm Sandy, the largest Atlantic hurricane on record, left more than 10 million people on the East Coast without power, nearly a third of our employee and contractor crews departed Wisconsin to assist with the recovery. Our crews restored some of the hardest-hit sections of the New York metropolitan area and demonstrated that our commitment to customer satisfaction extends well beyond our service area. We received an Edison Electric Institute Emergency Assistance Award in recognition of our response.

FINANCIAL HIGHLIGHTS

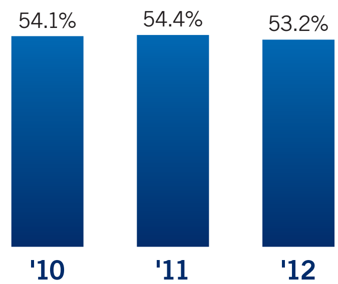
EARNINGS PER SHARE – CONTINUING OPERATIONS



DIVIDENDS PER SHARE[a]



YEAR-END DEBT TO TOTAL CAPITAL[b]



a. The quarterly dividend was increased from 30 cents per share to 34 cents per share in the first quarter of 2013.

b. Attributes $250 million of 2007 Series A Junior Subordinated Notes to common equity. A majority of the rating agencies currently attribute at least 50% common equity to these securities. For further details, see page F-18.

BEST IN THE MIDWEST — AGAIN

For the eighth time in 11 years, We Energies was named the most reliable utility in the Midwest. The award recognizes utilities that excel in providing customer care and delivering the most reliable electric service to customers.

GALE E. KLAPPA

Chairman, President, and Chief Executive Officer

TO OUR STOCKHOLDERS,

It was the 19th century — a different time and a different world — when the American poet Ralph Waldo Emerson wrote…"the years teach much which the days never know."

That phrase has echoed through history. But it has particular meaning for our company and for our industry today as we work to power the economy with a reliable, cost-effective supply of clean energy.

The years have taught us that there is no perfect fuel source…that over reliance on a single fuel is not a sound strategy…and that a portfolio of assets rich in fuel diversity is the key to meeting our customers' energy needs for the long term.

Our Power the Future plan, which is now complete, applied this fundamental lesson.

Over the past decade, we've modernized our fleet of power plants. We've retired a number of older, less-efficient units. We've added state-of-the-art environmental controls at our most productive facilities.

We've added 50 percent more capacity to our fleet — capacity that is equally balanced between coal and natural gas. We've built the two largest wind farms in Wisconsin and, later this year, we plan to complete a new biomass-fueled power plant that will burn wood waste from the northern Wisconsin forests.

Today, our operating fleet is rich in fuel diversity. And we've reduced our emissions by 80 percent since the year 2000.

It didn't take long before these assets were put to the test. This past summer, on July 5 and 6, as temperatures rose above 100 degrees, we were asked to operate our new coal- and natural gas-fired units at or above their maximum summer capacity ratings to help keep the lights on and commerce flowing. And I'm pleased to report that our Power the Future units performed exceptionally well.

MILESTONES ACHIEVED

Overall, 2012 was a remarkable year for Wisconsin Energy. We achieved milestones in customer satisfaction, employee safety, and network reliability.

We attained the highest customer satisfaction ratings in the past decade, achieved the best safety record in the history of the company, and we were named the most reliable utility in the Midwest for the eighth time in the past 11 years.

Overall, 2012 was a remarkable year for Wisconsin Energy.

Financially, we delivered record net income and record earnings per share — $546 million and $2.35 per share. Both were notable increases over 2011. We also made significant progress toward a dividend payout that is more competitive with our peers. More on our dividend policy a bit later in this letter.

A number of factors contributed to our strong financial performance in 2012, starting with the weather. We began 2012 with the warmest winter in 122 years, followed by a summer heat wave. In fact, 2012 was the warmest year on record in our region, breaking a mark that was set in 1931.

Our 2012 earnings were also driven by a $1.3 billion investment in modern environmental controls for the older coal-fired units at our Oak Creek site and by a full year of operation at our Glacier Hills Wind Park.

Energy sales to our large commercial and industrial customers — excluding the iron ore mines that we serve in Michigan's Upper Peninsula — dropped by 0.7 percent during the year. This was slightly better than our expectations. Our plan for 2012 projected a decline in sales to our large commercial and industrial group because two customers began using their own self-generation. Excluding these two customers and the iron ore mines, energy sales to our large customer segment actually rose by 1.1 percent for the full year.

Wisconsin Energy stock outperformed the utility sector by a wide margin.

An encouraging uptick in new customer connections also continued during 2012. New electric service installations were up by 8.7 percent, and connections of new natural gas customers rose by 13 percent over the prior year.

2012 was a year that saw utility stocks lag the major market indices. Uncertainty over future tax rates on dividends weighed heavily on utility shares, particularly in the fourth quarter as the debate continued in Washington over the "fiscal cliff." I'm pleased to note, however, that Wisconsin Energy stock outperformed the utility sector by a wide margin. Our shares set 35 new all-time trading highs during the year, reaching $41.48 per share on August 1.

Over the past decade, our total shareholder return has outperformed the investment returns of the Dow Jones Industrials, the S&P 500, NASDAQ, and all the major utility indexes. In fact, as you can see from the performance table on this page, our total shareholder return for the past five years was nearly four times greater than the next best alternative.

TOTAL SHAREHOLDER RETURN*

Five-Year Performance (2008–2012)

WISCONSIN ENERGY	**76.2%**
Dow Jones Industrial Average	13.8%
S&P 500 Index	8.6%
NASDAQ Composite Index	20.4%
Philadelphia Utility Index	0.3%
S&P Electric Index	–4.5%

*Stock price appreciation plus reinvested dividends.

DIVIDEND INCREASE

Of course, a significant portion of the total return that we deliver to our shareholders comes in the form of dividends. And, as we turned the page to 2013, our board of directors took two important steps.

First, the directors raised the quarterly dividend on our company's common stock to 34 cents a share, effective with the first quarter payment of 2013. The new dividend is equivalent to an annual rate of $1.36 a share — an increase of 13.3 percent.

Second, the board affirmed our policy to achieve a dividend payout ratio of 60 percent of earnings in 2014. In addition, the board adopted a follow-on policy targeting a dividend payout that trends to 65 to 70 percent of earnings in 2017. This policy should support double-digit growth in the dividend in 2014 and 7 to 8 percent growth in the years 2015 through 2017.

The strong, positive cash flows from our underlying business will help support our dividend policy as well as the share repurchase program that the board authorized. Through the end of 2012, we've returned additional value to shareholders by repurchasing nearly $152 million of our common stock at an average price of $32.63 a share.

PROGRESS ON ESSENTIAL INFRASTRUCTURE

Earlier in this letter, I mentioned that our Power the Future construction is complete. But there is much more work to do — installing new environmental controls, renewing and strengthening our distribution networks, and completing the renewable energy projects that are necessary to meet the standard set by the state of Wisconsin for the year 2015.

We made excellent progress on these projects during 2012. We completed the air quality control upgrades for the four older units at our Oak Creek site — upgrades that are dramatically reducing emissions from these units. At just under $900 million, this was the second largest construction project in company history. It was completed on time and slightly better than budget.

Progress also continued on the 50-megawatt biomass plant in Rothschild, Wisconsin. Construction is approximately 70 percent complete, and we're on schedule for commercial operation by the end of this year. The unit will efficiently produce electricity for the grid and steam for the paper mill owned and operated on the same site by Domtar Corporation. Our investment in the biomass plant is expected to total between $245 million and $255 million.

MOVING FORWARD

We're also studying ways to reduce the fuel costs at our Oak Creek expansion units. You'll recall that these new units were placed into service in 2010 and 2011 and are permitted to burn bituminous coal from the eastern United States.

However, in the decade since we first applied for authority to build, market forces have nearly tripled the price differential between eastern bituminous coal and western sub-bituminous coal. Because we expect a price differential to remain in place for the foreseeable future, we've asked the Wisconsin Department of Natural Resources for a revised air permit that will allow us to test burn a blend of eastern and western coals at our Oak Creek expansion units. We believe this project could significantly lower fuel costs for our customers.

In addition, we've been working to identify a life extension option for our Presque Isle Power Plant in Marquette, Michigan — an option that would be beneficial for our customers in light of proposed changes in federal environmental rules.

In late November, we signed a definitive agreement with Wolverine Power Cooperative that calls for Wolverine to acquire a minority interest in the plant by funding new state-of-the-art emission controls for the facility.

The joint venture will not reduce our investment in the plant, but we expect that it will reduce our operating costs. We will seek approvals from the Michigan and Wisconsin commissions this year. We hope to begin construction in 2014.

In Milwaukee, we announced plans to convert the fuel source for our Valley Power Plant from coal to natural gas. The Valley plant produces electricity and provides voltage support for Milwaukee's downtown business center. It also delivers a reliable supply of steam to heat hundreds of downtown buildings. Our analysis shows that converting the fuel source for the plant will reduce our operating costs and enhance the environmental performance of the Valley units.

We plan to seek regulatory approval to modify the Valley plant. The project could be completed by late 2015 at an estimated cost of $60 million to $65 million. We believe the plan we've put in place will secure Valley's role in meeting the energy needs of a vibrant downtown Milwaukee for many years to come.

I should also point out that we're investigating the need to expand our natural gas distribution network in western Wisconsin. The region will need additional supplies of natural gas to meet demand from homes, businesses, and the growing sand mining industry in that part of the state. We're preparing to file for commission approval to invest approximately $150 million in the first phase of this major distribution project.

Our capital spending plan calls for investing $3.2 billion to $3.5 billion over the five-year period through 2017.

Our capital spending plan calls for investing $3.2 billion to $3.5 billion over the five-year period through 2017. In addition to the projects I've mentioned, our major focus will be on needed upgrades to our aging infrastructure — the building blocks of our delivery business — pipes, poles, wires, transformers, and substations. These projects will be smaller in scale than the megaprojects we've completed over the past decade. But this work is essential to maintaining our status as the most reliable utility in the Midwest.

STANDING THE TEST OF TIME

History tells us that companies truly built to last — organizations that deliver enduring value over time — adapt to change and execute their plans with a laser focus on integrity and customer satisfaction.

For more than 100 years, Wisconsin Energy has stood the test of time. Today, we look to a future marked by resilience and growth. I believe our best days are ahead.

On behalf of our entire management team, thank you for your confidence, your support, and your investment in Wisconsin Energy.

Sincerely,

Gale Klappa

Gale E. Klappa
Chairman, President, and Chief Executive Officer
March 5, 2013

STRENGTHENING OUR DISTRIBUTION SYSTEM

We're making significant investments to strengthen the reliability of our distribution networks — poles, wires, pipes, transformers and substations — the building blocks of our delivery business. The plan includes replacing 18,500 power poles and rebuilding 2,000 miles of distribution lines by 2017.

ROTHSCHILD BIOMASS COGENERATION PLANT

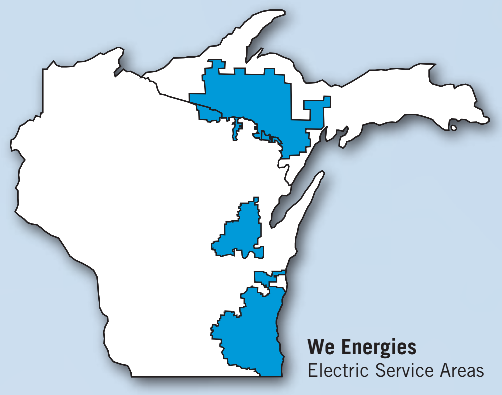
The Rothschild Biomass Cogeneration Plant will burn wood waste from forests in northern Wisconsin to produce electricity for the grid and steam for Domtar Corporation's paper mill. Construction is about 70 percent complete and commercial operation is expected to begin in late 2013.

WISCONSIN ENERGY CORPORATION (NYSE: WEC) is one of the nation's premier energy companies with more than $14 billion of assets and a diversified portfolio of businesses engaged in electric generation and the distribution of electricity, natural gas and steam.

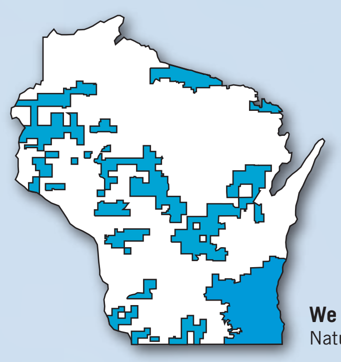
Wisconsin Energy's principal utility, We Energies, serves more than 1.1 million electric customers in Wisconsin and Michigan's Upper Peninsula and 1.1 million natural gas customers in Wisconsin. The company's other major subsidiary, We Power, designs, builds and owns electric generating plants.

Headquartered in Milwaukee, Wisconsin Energy is a component of the S&P 500 with approximately 4,500 employees and more than 41,000 stockholders of record.

ELECTRIC CUSTOMERS AS OF DEC. 31, 2012: 1,125,700



NATURAL GAS CUSTOMERS AS OF DEC. 31, 2012: 1,074,000



◀ The final portion of a 265-foot stack is erected at our biomass cogeneration plant in Rothschild, Wisconsin. With state-of-the-art emission control technology and the retirement of Domtar's existing boilers, air emissions from the site are expected to drop by approximately 30 percent when the project is complete.

2012 ANNUAL FINANCIAL STATEMENTS AND REVIEW OF OPERATIONS

Wisconsin Energy Corporation

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:

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
PIPP	Presque Isle Power Plant
PSGS	Paris Generating Station
PWGS	Port Washington Generating Station
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
ERGSS	Elm Road Generating Station Supercritical, LLC
WECC	Wisconsin Energy Capital Corporation
Wispark	Wispark LLC
Federal and State Regulatory Agencies	
CFTC	Commodity Futures Trading Commission
DOE	United States Department of Energy
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	
Act 141	2005 Wisconsin Act 141
BART	Best Available Retrofit Technology
BTA	Best Technology Available
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CO_2	Carbon Dioxide
CSAPR	Cross-State Air Pollution Rule
MATS	Mercury and Air Toxics Standards
NAAQS	National Ambient Air Quality Standards
NOV	Notice of Violation
NO_x	Nitrogen Oxide
$PM_{2.5}$	Fine Particulate Matter
RACT	Reasonably Available Control Technology
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
Other Terms and Abbreviations	
AQCS	Air Quality Control System
ARRs	Auction Revenue Rights
Bechtel	Bechtel Power Corporation
Compensation Committee	Compensation Committee of the Board of Directors

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:

Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
Edison Sault	Edison Sault Electric Company
ERISA	Employee Retirement Income Security Act of 1974
Exchange Act	Securities Exchange Act of 1934, as amended
Fitch	Fitch Ratings
FTRs	Financial Transmission Rights
GCRM	Gas Cost Recovery Mechanism
Junior Notes	Wisconsin Energy's 2007 Series A Junior Subordinated Notes due 2067
LMP	Locational Marginal Price
MISO	Midwest Independent Transmission System Operator, Inc.
MISO Energy Markets	MISO Energy and Operating Reserves Market
Montfort	Montfort Wind Energy Center
Moody's	Moody's Investor Service
NDAA	National Defense Authorization Act
NYMEX	New York Mercantile Exchange
OTC	Over-the-Counter
Plan	The Wisconsin Energy Corporation Retirement Account Plan
Point Beach	Point Beach Nuclear Power Plant
PTF	Power the Future
PUHCA 2005	Public Utility Holding Company Act of 2005
RCC	Replacement Capital Covenant dated May 11, 2007
RTO	Regional Transmission Organization
Settlement Agreement	Settlement Agreement and Release between Elm Road Services, LLC and Bechtel effective as of December 16, 2009
S&P	Standard & Poor's Ratings Services
WPL	Wisconsin Power and Light Company, a subsidiary of Alliant Energy Corp.
Wolverine	Wolverine Power Supply Cooperative, Inc.

Measurements

Btu	British Thermal Unit(s)
Dth	Dekatherm(s) (One Dth equals one million Btu)
kW	Kilowatt(s) (One kW equals one thousand Watts)
kWh	Kilowatt-hour(s)
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
ARO	Asset Retirement Obligation
ASU	Accounting Standards Update
CWIP	Construction Work in Progress
FASB	Financial Accounting Standards Board
GAAP	Generally Accepted Accounting Principles
IFRS	International Financial Reporting Standards
OPEB	Other Post-Retirement Employee Benefits

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

Certain statements contained in this report are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934, 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 future rate cases and negotiations, including recovery of 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, as well as upgrades to our electric and natural gas distribution systems.

- 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.

- 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.
- 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 (IFRS) 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.
- Potential strategic business opportunities, including acquisitions and/or dispositions of assets or businesses, which we cannot ensure will be beneficial for us.
- Incidents affecting the U.S. electric grid or operation of generating facilities.
- 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.

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.

BUSINESS OF THE COMPANY

Wisconsin Energy Corporation was incorporated in the state of Wisconsin in 1981 and became a diversified holding company in 1986. We maintain our principal executive offices in Milwaukee, Wisconsin. 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.

We conduct our operations primarily in two reportable segments: a utility energy segment and a non-utility energy segment. 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 and Wisconsin Gas, operating together under the trade name of "We Energies." We Energies serves approximately 1,125,700 electric customers in Wisconsin and the Upper Peninsula of Michigan. We Energies serves approximately 1,074,000 gas customers in Wisconsin and approximately 460 steam customers in metropolitan Milwaukee, Wisconsin.

Non-Utility Energy Segment: Our non-utility energy segment consists primarily of We Power, which owns and leases to Wisconsin Electric generation plants constructed as part of our Power the Future (PTF) strategy. All four of the plants constructed as part of PTF have been placed in service. Port Washington Generating Station Unit 1 (PWGS 1) and Port Washington Generating Station Unit 2 (PWGS 2) are being leased to Wisconsin Electric under long-term leases that run for 25 years. Oak Creek expansion Unit 1 (OC 1) and Oak Creek expansion Unit 2 (OC 2) are being leased to Wisconsin Electric under long-term leases that run for 30 years.

For further financial information about our business segments, see Results of Operations in Management's Discussion and Analysis of Financial Condition and Results of Operations and Note N -- Segment Reporting in the Notes to Consolidated Financial Statements.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

CORPORATE DEVELOPMENTS AND STRATEGY

We have three primary investment opportunities and earnings streams: our regulated utility business; our investment in ATC; and our generation plants within our non-utility energy segment.

Our regulated utility business primarily consists of electric generation assets and the electric and gas distribution assets that serve the electric and gas customers of Wisconsin Electric and Wisconsin Gas. During 2012, our regulated utility earned $647.7 million of operating income. Over the next three years, we expect to invest approximately $2.0 billion in this business to construct renewable generation, to convert the fuel source for the Valley Power Plant (VAPP) from coal to natural gas, to update the electric and gas distribution infrastructure, and for other utility projects.

We have a $378.3 million investment in ATC, which represents a 26.2% ownership interest. Our 2012 pre-tax earnings from ATC totaled $65.7 million and we received $52.6 million in dividends from ATC. Over the next three years, we expect to make capital contributions of approximately $40 million in ATC as it continues to invest in transmission projects. During the same period, we expect to invest $47 million in ATC through undistributed earnings.

Our non-utility energy segment consists primarily of the four generation plants constructed as part of our PTF strategy. All four plants have been placed in service and are being leased to Wisconsin Electric under long-term leases that run for 25 years (PWGS 1 and PWGS 2) and 30 years (OC 1 and OC 2). We recognize revenues on a levelized basis over the life of the lease. During 2013, we expect this segment's operating income to be between $360 million and $365 million. The PTF strategy was developed with the primary goal of constructing these power plants. Over the next three years, we do, however, expect to invest approximately $97 million in this segment on smaller capital projects, including the Oak Creek expansion fuel flexibility project. For additional information on this project, see Factors Affecting Results, Liquidity and Capital Resources -- Other Matters.

RESULTS OF OPERATIONS

CONSOLIDATED EARNINGS

The following table compares our operating income by business segment and our net income for 2012, 2011 and 2010:

Wisconsin Energy Corporation	2012	2011	2010
	(Millions of Dollars)		
Utility Energy	$ 647.7	$ 544.8	$ 564.0
Non-Utility Energy	358.8	348.9	252.4
Corporate and Other	(6.2)	(6.4)	(6.0)
Total Operating Income	1,000.3	887.3	810.4
Equity in Earnings of Transmission Affiliate	65.7	62.5	60.1
Other Income and Deductions, net	34.8	62.7	40.2
Interest Expense, net	248.2	235.8	206.4
Income from Continuing Operations Before Income Taxes	852.6	776.7	704.3
Income Tax Expense	306.3	263.9	249.9
Income from Continuing Operations	546.3	512.8	454.4
Income from Discontinued Operations, Net of Tax	—	13.4	2.1
Net Income	$ 546.3	$ 526.2	$ 456.5
Diluted Earnings Per Share			
Continuing Operations	$ 2.35	$ 2.18	$ 1.92
Discontinued Operations	—	0.06	0.01
Total Diluted Earnings Per Share	$ 2.35	$ 2.24	$ 1.93

An analysis of contributions to operating income by segment and a more detailed analysis of results follows.

UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

The following table summarizes our utility energy segment's operating income during 2012, 2011 and 2010:

Utility Energy Segment	2012	2011	2010
	(Millions of Dollars)		
Operating Revenues			
Electric	$ 3,193.9	$ 3,211.3	$ 2,936.3
Gas	962.6	1,181.2	1,190.2
Other	34.3	39.0	38.8
Total Operating Revenues	4,190.8	4,431.5	4,165.3
Operating Expenses			
Fuel and Purchased Power	1,103.8	1,174.5	1,104.7
Cost of Gas Sold	545.8	728.7	751.5
Other Operation and Maintenance	1,476.5	1,613.4	1,587.0
Depreciation and Amortization	296.4	257.0	251.4
Property and Revenue Taxes	120.6	113.1	105.1
Total Operating Expenses	3,543.1	3,886.7	3,799.7
Amortization of Gain	—	—	198.4
Operating Income	$ 647.7	$ 544.8	$ 564.0

2012 vs. 2011: Our utility energy segment contributed $647.7 million of operating income during 2012 compared with $544.8 million of operating income during 2011. The increase in operating income was primarily caused by decreased other operation and maintenance expense and decreased fuel and purchased power expenses.

2011 vs. 2010: Our utility energy segment contributed $544.8 million of operating income during 2011 compared with $564.0 million of operating income during 2010. The decrease in operating income was primarily caused by increased other operation and maintenance expense and unfavorable weather during 2011 as compared to 2010, partially offset by wholesale electric pricing increases and electric sales growth.

Electric Utility Gross Margin

The following table compares our electric utility gross margin during 2012 with similar information for 2011 and 2010, including a summary of electric operating revenues and electric sales by customer class:

	Electric Revenues and Gross Margin			MWh Sales		
Electric Utility Operations	2012	2011	2010	2012	2011	2010
	(Millions of Dollars)			(Thousands)		
Customer Class						
Residential	$ 1,163.9	$ 1,159.2	$ 1,114.3	8,317.7	8,278.5	8,426.3
Small Commercial/Industrial	1,013.6	1,006.9	922.2	8,860.0	8,795.8	8,823.3
Large Commercial/Industrial	744.3	763.7	677.1	9,710.7	9,992.2	9,961.5
Other - Retail	22.8	22.9	21.9	154.8	153.6	155.3
Total Retail	2,944.6	2,952.7	2,735.5	27,043.2	27,220.1	27,366.4
Wholesale - Other	144.4	154.0	134.6	1,566.6	2,024.8	2,004.6
Resale - Utilities	53.4	69.5	40.4	1,642.4	2,065.7	1,103.8
Other Operating Revenues	51.5	35.1	25.8	—	—	—
Total	3,193.9	3,211.3	2,936.3	30,252.2	31,310.6	30,474.8
Fuel and Purchased Power						
Fuel	541.6	644.4	570.5			
Purchased Power	548.7	514.8	521.0			
Total Fuel and Purchased Power	1,090.3	1,159.2	1,091.5			
Total Electric Gross Margin	$ 2,103.6	$ 2,052.1	$ 1,844.8			
Weather - Degree Days (a)						
Heating (6,662 Normal)				5,704	6,633	6,183
Cooling (696 Normal)				1,041	793	944

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

Electric Utility Revenues and Sales

2012 vs. 2011: Our electric utility operating revenues decreased by $17.4 million, or 0.5%, when compared to 2011. The most significant factors that caused a change in revenues were:

- Favorable weather as compared to the prior year that increased electric revenues by an estimated $28.5 million.
- Other operating revenues increased by approximately $16.4 million, driven by the $25.9 million amortization of a settlement with the United States Department of Energy (DOE). For additional information on the DOE settlement, see Factors Affecting Results, Liquidity and Capital Resources -- Nuclear Operations.
- A planned outage at an iron ore mine of our largest customer and the conversion to self-generation of two other large customers decreased electric revenues by an estimated $20.4 million.
- A $16.2 million reduction in sales for resale due to reduced sales into the MISO Energy Markets.
- Lower MWh sales to our wholesale customers, which decreased revenue by an estimated $12.4 million as compared to 2011.

As measured by cooling degree days, 2012 was 49.6% warmer than normal, and 31.3% warmer than 2011. We believe the warmer summer weather was the primary reason for the 0.5% increase in residential sales and the 0.7% increase in small commercial/industrial sales. The increase due to warmer summer weather was partially offset by reduced sales from warmer winter weather in the first quarter of 2012 as compared to the first quarter of 2011.

Sales to our large commercial/industrial customers decreased by 2.8% primarily due to the planned outage at an iron ore mine of our largest customer and the conversion to self-generation of two other large customers. Excluding sales to these three customers, MWh sales to large commercial/industrial customers increased by 1.1%. Wholesale sales decreased primarily due to the low market price of power in 2012 as compared to 2011, which caused some of these customers to obtain energy from the MISO market rather than through our contracts. The reduction did not impact the majority of revenue received from these customers, which is tied to demand. The lower market price of power also reduced our ability to sell energy into the MISO Energy Markets.

2011 vs. 2010: Our electric utility operating revenues increased by $275.0 million, or 9.4%, when compared to 2010. The most significant factors that caused a change in revenues were:

- 2011 increase of approximately $198.4 million, reflecting the reduction of Point Beach bill credits to retail customers. For information on the bill credits, see Amortization of Gain below.
- Net pricing increases totaling $48.8 million, which includes rates related to our 2010 fuel recovery request that became effective March 25, 2010, and our request to review 2011 fuel costs that became effective April 29, 2011. For information on these rate orders, see Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters.
- Unfavorable weather as compared to 2010 that decreased electric revenues by an estimated $40.5 million.
- A $20.4 million increase in revenue from energy sold into the MISO Energy Markets, which was driven by increased MWh generation from our Oak Creek expansion units.
- Net economic growth that increased electric revenues by an estimated $16.2 million as compared to 2010.
- Higher MWh sales to our wholesale customers, which increased revenue by an estimated $10.4 million as compared to 2010.

As measured by cooling degree days, 2011 was 11.8% warmer than normal, but 16.0% cooler than 2010. The 1.8% decrease in residential sales volumes in 2011 is primarily attributable to weather. The estimated 1.8% impact of cooler summer weather on our small commercial/industrial sales volumes was almost entirely offset by an estimated 1.5% increase in sales due to modest economic growth. Increased sales to our largest customers, two iron ore mines, accounted for the increase in sales to our large commercial/industrial customers. If these sales are excluded, sales to our large commercial/industrial customers decreased by approximately 1.2% for 2011 as compared to 2010 primarily because of previously announced plant closings.

Electric Fuel and Purchased Power Expenses

2012 vs. 2011: Our electric fuel and purchased power costs decreased by $68.9 million, or approximately 5.9%, when compared to 2011. This decrease was primarily caused by a 3.4% decrease in total MWh sales as well as a reduction in our average cost of fuel and purchased power because of lower natural gas prices.

2011 vs. 2010: Our electric fuel and purchased power costs increased by $67.7 million, or approximately 6.2%, when compared to 2010. This increase was primarily caused by a 2.7% increase in total MWh sales as well as increased coal and related transportation costs, partially offset by lower natural gas prices.

Gas Utility Revenues, Gross Margin and Therm Deliveries

The following table compares our total gas utility operating revenues and gross margin (total gas utility operating revenues less cost of gas sold) during 2012, 2011 and 2010. Operating revenues and cost of gas sold has declined over the last three years due to the decline in the commodity cost of natural gas during this three year period.

Gas Utility Operations	2012	2011	2010
	(Millions of Dollars)		
Operating Revenues	$ 962.6	$ 1,181.2	$ 1,190.2
Cost of Gas Sold	545.8	728.7	751.5
Gross Margin	$ 416.8	$ 452.5	$ 438.7

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 (GCRM). The following table compares our gas utility gross margin and therm deliveries by customer class during 2012, 2011 and 2010:

Gas Utility Operations	Gross Margin 2012	Gross Margin 2011	Gross Margin 2010	Therm Deliveries 2012	Therm Deliveries 2011	Therm Deliveries 2010
	(Millions of Dollars)			(Millions)		
Customer Class						
Residential	$ 267.9	$ 290.2	$ 282.2	676.4	776.8	741.2
Commercial/Industrial	88.8	101.5	95.8	390.6	461.7	429.6
Interruptible	1.7	1.8	2.2	14.6	16.0	19.4
Total Retail	358.4	393.5	380.2	1,081.6	1,254.5	1,190.2
Transported Gas	52.9	52.6	51.3	1,140.4	899.6	914.9
Other Operating	5.5	6.4	7.2	—	—	—
Total	$ 416.8	$ 452.5	$ 438.7	2,222.0	2,154.1	2,105.1
Weather - Degree Days (a)						
Heating (6,662 Normal)				5,704	6,633	6,183

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

2012 vs. 2011: Our total retail gas margin decreased by $35.1 million, or approximately 8.9%, when compared to 2011 primarily because of a decrease in sales volumes as a result of warmer winter weather. As measured by heating degree days, 2012 was 14.0% warmer than 2011 and 14.4% warmer than normal.

Transported gas volumes increased by 26.8% when compared to 2011. Virtually all of the volume increase related to gas used in electric generation, which has a small impact on margin.

2011 vs. 2010: Our gas margin increased by $13.8 million, or approximately 3.1%, when compared to 2010 primarily because of an increase in sales volumes as a result of colder winter weather in 2011 as compared to 2010. As measured by heating degree days, 2011 was 7.3% colder than 2010 and 0.3% colder than normal.

Other Operation and Maintenance Expense

2012 vs. 2011: Our other operation and maintenance expense decreased by $136.9 million, or approximately 8.5%, when compared to 2011. This decrease 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.

Our utility operation and maintenance expenses are influenced by, among other things, labor costs, employee benefit costs, plant outages and amortization of regulatory assets. We expect our 2013 other operation and maintenance expense to stay fairly flat because we anticipate that the 2013 Wisconsin Rate Case reinstatement of amortization on certain regulatory assets will be offset by an extension of the recovery period for certain regulatory assets and a significant reduction of escrowed bad debt expense.

2011 vs. 2010: Our other operation and maintenance expense increased by $26.4 million, or approximately 1.7%, when compared to 2010. Higher maintenance costs at one of our natural gas peaking plants, increased spending on forestry work for our electric distribution system and increased costs associated with the amortization of deferred PTF costs related to wholesale and Michigan customers were the primary drivers of the increase.

Depreciation and Amortization Expense

2012 vs. 2011: Depreciation and Amortization expense increased by $39.4 million, or approximately 15.3%, when compared to 2011. This increase was 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 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.

We expect depreciation and amortization expense to increase in 2013 primarily as a result of an increase in utility plant in service related to the Oak Creek AQCS project, which will have been in service a full year.

2011 vs. 2010: Depreciation and Amortization expense increased by $5.6 million, or approximately 2.2%, when compared to 2010. This increase was primarily because of an overall increase in utility plant in service.

Amortization of Gain

In connection with the September 2007 sale of Point Beach Nuclear Power Plant (Point Beach), we reached an agreement with our regulators to allow for the net gain on the sale to be used for the benefit of our customers. The majority of the benefits were returned to customers in the form of bill credits. The net gain was originally recorded as a regulatory liability, and it was amortized to the income statement as we issued bill credits to customers. When the bill credits were issued to customers, we transferred cash from the restricted accounts to the unrestricted accounts, adjusted for taxes. All bill credits associated with the sale of Point Beach were applied to customers as of December 31, 2010, and as a result, the Amortization of Gain was zero during 2012 and 2011 as compared to $198.4 million during 2010.

NON-UTILITY ENERGY SEGMENT CONTRIBUTION TO OPERATING INCOME

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

The table below reflects:

- A full year's earnings for 2012, 2011 and 2010 for:
- PWGS 1;
- PWGS 2;
- the coal handling system for the Oak Creek expansion; and
- the water intake system for the Oak Creek expansion.
- A full year's earnings for 2012 and 2011 and approximately eleven months of earnings for 2010 for OC 1; and
- A full year's earnings for 2012 and approximately eleven and a half months of earnings for 2011 for OC 2.

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

	2012	2011	2010
		(Millions of Dollars)	
Operating Revenues	$ 439.9	$ 435.1	$ 320.2
Operation and Maintenance Expense	14.0	13.7	14.3
Depreciation Expense	67.1	72.5	53.5
Operating Income (Loss)	$ 358.8	$ 348.9	$ 252.4

Non-utility energy segment operating income increased $9.9 million, or approximately 2.8%, primarily because of a decrease in depreciation expense related to finalized depreciable lives of the Oak Creek expansion units and a full year's earnings in 2012 for OC 2.

In 2013, we expect our non-utility energy segment operating revenue to increase approximately 2% to 3% to reflect the final approved construction costs for the Oak Creek expansion as part of the 2013 Wisconsin Rate Case. For further information, see Factors Affecting Results, Liquidity and Capital Resources -- Utility Rates and Regulatory Matters.

CORPORATE AND OTHER CONTRIBUTION TO OPERATING INCOME

2012 vs. 2011: Corporate and other affiliates had an operating loss of $6.2 million in 2012 compared with an operating loss of $6.4 million in 2011.

2011 vs. 2010: Corporate and other affiliates had an operating loss of $6.4 million in 2011 compared with an operating loss of $6.0 million in 2010.

CONSOLIDATED OTHER INCOME AND DEDUCTIONS, NET

Other Income and Deductions, net	2012	2011	2010
		(Millions of Dollars)	
AFUDC - Equity	$ 35.3	$ 59.4	$ 32.5
Gain on Property Sales	2.7	2.4	4.4
Other, net	(3.2)	0.9	3.3
Total Other Income and Deductions, net	$ 34.8	$ 62.7	$ 40.2

2012 vs. 2011: Other income and deductions, net decreased by approximately $27.9 million, or 44.5%, when compared to 2011. This decrease primarily relates to AFUDC - Equity 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.

During 2013, we expect to see a reduction in AFUDC - Equity as we expect to have fewer large construction projects.

2011 vs. 2010: Other income and deductions, net increased by approximately $22.5 million, or 56.0%, when compared to 2010. The increase in AFUDC - Equity is primarily related to the construction of the Oak Creek AQCS project and the Glacier Hills Wind Park.

CONSOLIDATED INTEREST EXPENSE, NET

Interest Expense, net	2012	2011	2010
		(Millions of Dollars)	
Gross Interest Costs	$ 264.1	$ 262.5	$ 258.7
Less: Capitalized Interest	15.9	26.7	52.3
Interest Expense, net	$ 248.2	$ 235.8	$ 206.4

2012 vs. 2011: Our net interest expense increased by $12.4 million, or 5.3%, as compared to 2011 primarily because of lower capitalized interest. Our capitalized interest decreased by $10.8 million primarily because we stopped capitalizing interest on the Oak Creek AQCS project when the emission control equipment went into service in March 2012 for units 5 and 6 and September 2012 for units 7 and 8, and the Glacier Hills Wind Park which went into service in December 2011.

During 2013, we expect to see higher net interest expense because of a reduction in capitalized interest as a result of the Oak Creek AQCS project emission control equipment going into service in 2012, partially offset by the expected increase in capitalized interest associated with the biomass plant which is expected to go into service by the end of 2013.

2011 vs. 2010: Our gross interest costs increased by $3.8 million, or 1.5%, during 2011, primarily because of higher average long-term debt balances as compared to 2010. In January 2011, we issued $420 million of long-term debt and used the net proceeds to repay short-term debt incurred to finance the construction of OC 2 and for other corporate purposes. In September 2011, Wisconsin Electric issued $300 million of long-term debt and used the net proceeds to repay short-term debt and for other general corporate purposes. In April 2011, we retired $450 million of long-term debt that matured, which partially offset the debt issuances. Our capitalized interest decreased by $25.6 million primarily because we stopped capitalizing interest on OC 2 when it was placed in service in January 2011. As a result, our net interest expense increased by $29.4 million, or 14.2%, as compared to 2010.

CONSOLIDATED INCOME TAX EXPENSE

2012 vs. 2011: Our effective tax rate applicable to continuing operations was 35.9% in 2012 compared to 34.0% in 2011. This increase in our effective tax rate was primarily the result of decreased AFUDC - Equity. For further information, see Note G -- Income Taxes in the Notes to Consolidated Financial Statements. We expect our 2013 annual effective tax rate to be between 37.0% and 38.0%.

2011 vs. 2010: Our effective tax rate applicable to continuing operations was 34.0% in 2011 compared to 35.5% in 2010. This reduction in our effective tax rate was primarily the result of increased AFUDC - Equity.

LIQUIDITY AND CAPITAL RESOURCES

CASH FLOWS

The following table summarizes our cash flows during 2012, 2011 and 2010:

	2012	2011	2010
		(Millions of Dollars)	
Cash Provided by (Used in)			
Operating Activities	$ 1,173.9	$ 993.4	$ 810.4
Investing Activities	$ (729.6)	$ (892.5)	$ (633.5)
Financing Activities	$ (422.8)	$ (111.3)	$ (172.6)

Operating Activities

2012 vs. 2011: Cash provided by operating activities was $1,173.9 million during 2012, which was an increase of $180.5 million over 2011. The largest increases in cash provided by operating activities related to higher net income, higher depreciation expense, and lower contributions to our benefit plans. Combined these items increased operating cash flows by $232.8 million as compared to 2011. Partially offsetting these items, our non-cash charges related to the amortization of certain regulatory assets and liabilities was $148.0 million lower during 2012 as compared to 2011 because the Public Service Commission of Wisconsin (PSCW) allowed us to suspend these amortizations in 2012.

2011 vs. 2010: Cash provided by operating activities was $993.4 million during 2011, which was an increase of $183.0 million over 2010. The largest increases in cash provided by operating activities related to higher net income, higher depreciation expense, higher deferred income tax benefits and the elimination of the amortization of the gain on the sale of Point Beach. Combined these items totaled $1,293.2 million during 2011 as compared to $680.4 million during 2010. The largest reduction in cash provided by operating activities related to our contributions to qualified benefit plans. During 2011, we contributed $277.4 million to our qualified benefit plans. We made no contributions to our qualified plans during 2010.

Investing Activities

2012 vs. 2011: Cash used in investing activities was $729.6 million during 2012, which was $162.9 million lower than 2011. This decrease was primarily caused by a decrease in capital expenditures and a decrease in our restricted cash. Our capital expenditures decreased by $123.8 million in 2012 compared to 2011, primarily because of decreased spending on the Oak Creek AQCS project which went into service in March and September of 2012. In 2011, we received $45.5 million in proceeds from the settlement with the DOE. The proceeds were treated as restricted cash, which was recorded as cash used in investing activities. In 2012, we released $42.8 million of the proceeds through bill credits and the reimbursement of costs. The decrease was offset by a reduction in proceeds from asset sales. In 2011, we received proceeds from asset sales totaling $41.5 million, which primarily relates to the sale of our interest in Edgewater Generating Unit 5, as compared to proceeds of $8.7 million in 2012.

The following table identifies capital expenditures by year:

Capital Expenditures	2012	2011	2010
	(Millions of Dollars)		
Utility	$ 697.3	$ 792.2	$ 687.0
We Power	5.5	31.2	109.3
Other	4.2	7.4	1.9
Total Capital Expenditures	$ 707.0	$ 830.8	$ 798.2

2011 vs. 2010: Cash used in investing activities was $892.5 million during 2011, which was $259.0 million higher than 2010. This increase in cash used primarily reflects changes in restricted cash and increased capital expenditures. During 2011, our restricted cash increased by $37.2 million primarily because of the nuclear fuel settlement we received from the DOE. During 2010, our restricted cash decreased by $186.2 million due to the release of restricted cash related to the Point Beach bill credits. In addition, capital expenditures increased by approximately $32.6 million during 2011 as compared to 2010 primarily due to increased spending related to the construction of the Oak Creek AQCS project and the Glacier Hills Wind Park in 2011 as compared to 2010.

Financing Activities

The following table summarizes our cash flows from financing activities:

	2012	2011	2010
	(Millions of Dollars)		
Net Increase (Decrease) in Debt	$ (43.8)	$ 265.4	$ 71.1
Dividends on Common Stock	(276.3)	(242.0)	(187.0)
Common Stock Repurchased, Net	(103.4)	(139.5)	(65.7)
Other	0.7	4.8	9.0
Cash (Used in) Provided by Financing	$ (422.8)	$ (111.3)	$ (172.6)

2012 vs. 2011: Cash used in financing activities was $422.8 million during 2012, compared to $111.3 million during 2011. In 2012, we issued $251.8 million in long term debt, including $250.0 million by Wisconsin Electric, and used the proceeds to repay short-term debt and for other general corporate purposes. In 2011, we issued $720.0 million of long-term debt. In addition, we retired $466.6 million of long-term debt in 2011. Short-term debt decreased $275.3 million in 2012 compared to a $12.0 million increase in 2011.

Our common stock dividends increased in 2012 as we raised our quarterly dividend rate by 15.4%. In January 2013, our Board of Directors approved an increase in our quarterly common stock dividend of $.04 per share, or approximately 13.3%.

In addition, on May 5, 2011, our Board of Directors authorized a share repurchase program for up to $300 million of our common stock through the end of 2013. Funds for the repurchases are expected to continue to come from internally generated funds and working capital supplemented, if required in the short-term, by the sale of commercial paper. The repurchase program does not obligate Wisconsin Energy to acquire any specific number of shares and may be suspended or terminated by the Board of Directors at any time. In 2012, we repurchased approximately 1.5 million shares in the open market pursuant to this program at a total cost of $51.8 million, compared to 3.2 million shares at a cost of $100 million in 2011.

2011 vs. 2010: Cash used in financing activities was $111.3 million during 2011, compared to $172.6 million during 2010. During 2011, we issued a total of $720.0 million of long-term debt and retired $466.6 million of long-term debt. The net proceeds from the new issuance of debt were used to repay short-term debt and for other corporate purposes.

Our common stock dividends increased in 2011 as we raised our dividend rate by 30.0%.

No new shares of Wisconsin Energy's common stock were issued in 2012, 2011 or 2010. During these years, our independent plan agents purchased, in the open market, 2.8 million shares at a cost of $101.4 million, 3.0 million shares at a cost of $93.9 million and 5.8 million shares at a cost of $156.6 million, respectively, to fulfill exercised stock options and restricted stock awards. In 2012, 2011 and 2010, we received proceeds of $49.8 million, $54.4 million and $90.9 million, respectively, related to the exercise of stock options. In addition, we instructed our independent agents to purchase shares of our common stock in the open market to satisfy our obligations under our stock purchase and dividend reinvestment plan and various employee benefit plans.

CAPITAL RESOURCES AND REQUIREMENTS

Working Capital

As of December 31, 2012, our current liabilities exceeded our current assets by approximately $129.4 million. Included in our current liabilities is approximately $412.1 million of long-term debt due currently. We do not expect this to have any impact on our liquidity because we believe we have adequate back-up lines of credit in place for on-going operations. We also have access to the capital markets to finance our construction program and to refinance current maturities of long-term debt if necessary.

Liquidity

We anticipate meeting our capital requirements during 2013 and beyond 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.

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

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

As of December 31, 2012, we had approximately $1.2 billion of available, undrawn lines under our bank back-up credit facilities. As of December 31, 2012, we had approximately $394.6 million of commercial paper outstanding on a consolidated basis that was supported by the available lines of credit. During 2012, our maximum commercial paper outstanding was $669.9 million with a weighted-average interest rate of 0.28%. For additional information regarding our commercial paper balances during 2012, see Note J -- Short-Term Debt in the Notes to Consolidated Financial Statements.

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 December 31, 2012:

Company	Total Facility	Letters of Credit	Credit Available	Facility Expiration
		(Millions of Dollars)		
Wisconsin Energy	$ 400.0	$ 0.4	$ 399.6	December 2017
Wisconsin Electric	$ 500.0	$ 5.9	$ 494.1	December 2017
Wisconsin Gas	$ 350.0	$ —	$ 350.0	December 2017

On December 12, 2012, Wisconsin Energy entered into an unsecured five-year $400 million bank back-up credit facility to replace a $450 million three-year credit facility with an expiration date of December 2013. This new facility will expire in December 2017.

On December 12, 2012, Wisconsin Electric entered into an unsecured five-year $500 million bank back-up credit facility to replace a $500 million three-year credit facility with an expiration date of December 2013. This new facility will expire in December 2017.

On December 12, 2012, Wisconsin Gas entered into an unsecured five-year $350 million bank back-up credit facility to replace a $300 million three-year credit facility with an expiration date of December 2013. This new facility will expire in December 2017.

Each of these facilities has a renewal provision for two one-year extensions, subject to lender approval.

The following table shows our capitalization structure as of December 31, 2012 and 2011, as well as an adjusted capitalization structure that we believe is consistent with the manner in which the rating agencies currently view Wisconsin Energy's 2007 Series A Junior Subordinated Notes due 2067 (Junior Notes):

	2012		2011	
Capitalization Structure	Actual	Adjusted	Actual	Adjusted
	(Millions of Dollars)			
Common Equity	$ 4,135.1	$ 4,385.1	$ 3,963.3	$ 4,213.3
Preferred Stock of Subsidiary	30.4	30.4	30.4	30.4
Long-Term Debt (including current maturities)	4,865.9	4,615.9	4,646.9	4,396.9
Short-Term Debt	394.6	394.6	669.9	669.9
Total Capitalization	$ 9,426.0	$ 9,426.0	$ 9,310.5	$ 9,310.5
Total Debt	$ 5,260.5	$ 5,010.5	$ 5,316.8	$ 5,066.8
Ratio of Debt to Total Capitalization	55.8%	53.2%	57.1%	54.4%

For a summary of the interest rate, maturity and amount outstanding of each series of our long-term debt on a consolidated basis, see the Consolidated Statements of Capitalization.

Included in Long-Term Debt on our Consolidated Balance Sheet as of December 31, 2012 and 2011 is $500 million aggregate principal amount of the Junior Notes. The adjusted presentation attributes $250 million of the Junior Notes to Common Equity and $250 million to Long-Term Debt. We believe this presentation is consistent with the 50% or greater equity credit the majority of rating agencies currently attribute to the Junior Notes.

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

As described in Note H -- Common Equity, in the Notes to Consolidated Financial Statements, certain restrictions exist on the ability of our subsidiaries to transfer funds to us. We do not expect these restrictions to have any material effect on our operations or ability to meet our cash obligations.

Wisconsin Electric is the obligor under two series of tax exempt pollution control refunding bonds in outstanding principal amounts of $147 million. In August 2009, Wisconsin Electric terminated letters of credit that provided credit and liquidity support for the bonds, which resulted in a mandatory tender of the bonds. Wisconsin Electric issued commercial paper to fund the purchase of the bonds. As of December 31, 2012, the repurchased bonds were still outstanding, but were reported as a reduction in our consolidated long-term debt because they are held by Wisconsin Electric. Depending on market conditions and other factors, Wisconsin Electric may change the method used to determine the interest rate on the bonds and have them remarketed to third parties.

Bonus Depreciation Provisions

As a result of the enactment of tax legislation extending the bonus depreciation rules, we recognized increased federal tax depreciation through 2012 relating to assets placed into service including the Glacier Hills Wind Park, OC 1, OC 2 and the Oak Creek AQCS project. As a result of this increased federal tax depreciation we did not make federal income tax payments for 2012 and do not anticipate making federal income tax payments for 2013. The American Taxpayer Relief Act of 2012 was signed into law on January 2, 2013, which extended the 50% bonus depreciation rules to include assets placed in service in 2013.

Credit Rating Risk

We do not have any credit agreements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. We do have certain agreements in the form of commodity contracts and employee benefit plans that could require collateral or a termination payment in the event of a credit rating change to below BBB- at Standard & Poor's Ratings Services (S&P) and/or Baa3 at Moody's Investor Service (Moody's). As of December 31, 2012, we estimate that the collateral or the termination payments required under these agreements totaled approximately $225.7 million. Generally, collateral may be provided by a

Wisconsin Energy guaranty, letter of credit or cash. We also have other commodity contracts that in the event of a credit rating downgrade could result in a reduction of our unsecured credit granted by counterparties.

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

In November 2012, Moody's affirmed the ratings of Wisconsin Gas (commercial paper, P-1; senior unsecured, A2). In December 2012, Moody's affirmed the ratings of Wisconsin Energy (commercial paper, P-2; senior unsecured, A3; junior unsecured, Baa1), Wisconsin Electric (commercial paper, P-1; senior unsecured, A2), Elm Road Generating Station Supercritical, LLC (ERGSS) (senior notes, A2) and Wisconsin Energy Capital Corporation (WECC) (senior unsecured, A3). Moody's affirmed the stable ratings outlook assigned to each company.

In June 2012, S&P affirmed the ratings of Wisconsin Energy (commercial paper, A-2; senior unsecured, BBB+; junior unsecured, BBB), Wisconsin Electric (commercial paper, A-2; senior unsecured, A-), Wisconsin Gas (commercial paper, A-2; senior unsecured, A-) and ERGSS (senior notes, A-). S&P also revised the ratings outlooks assigned to each company from stable to positive.

In June 2012, Fitch Ratings (Fitch) affirmed the ratings of Wisconsin Energy (commercial paper, F2; senior unsecured, A-; junior unsecured, BBB), Wisconsin Electric (commercial paper, F1; senior unsecured, A+), Wisconsin Gas (commercial paper, F1; senior unsecured, A+), WECC (senior unsecured, A-) and ERGSS (senior notes, A+). Fitch also affirmed the stable ratings outlooks assigned to each company.

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

Capital Requirements

Capital Expenditures: Our estimated 2013, 2014 and 2015 capital expenditures are as follows:

Capital Expenditures	2013	2014	2015
		(Millions of Dollars)	
Utility	$ 655.9	$ 589.0	$ 741.0
We Power	30.6	34.3	28.6
Other	6.2	7.5	8.5
Total	$ 692.7	$ 630.8	$ 778.1

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

Common Stock Matters: During 2013, we expect to continue to repurchase our common stock under the share repurchase program approved by the Board on May 5, 2011, and to pay a quarterly dividend of $0.34 per share as approved by the Board in January 2013.

Investments in Outside Trusts: We use outside trusts to fund our pension and certain other post-retirement obligations. These trusts had investments of approximately $1.7 billion as of December 31, 2012. These trusts hold investments that are subject to the volatility of the stock market and interest rates.

During 2012, we contributed $95.6 million to our qualified pension plans and $4.4 million to our qualified Other Post-Retirement Employee Benefit (OPEB) plans. During 2011, we contributed $236.4 million to our qualified pension plans and $41.0 million to our qualified OPEB plans. Future contributions to the plans will be dependent upon many factors, including the performance of existing plan assets and long-term discount rates. For additional information, see Note M -- Benefits in the Notes to Consolidated Financial Statements.

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 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 additional information, see Note F -- Variable Interest Entities in the Notes to Consolidated Financial Statements in this report.

Contractual Obligations/Commercial Commitments: We have the following contractual obligations and other commercial commitments as of December 31, 2012:

	Payments Due by Period				
Contractual Obligations (a)	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
	(Millions of Dollars)				
Long-Term Debt Obligations (b)	$ 9,100.8	$ 647.8	$ 1,171.1	$ 504.6	$ 6,777.3
Capital Lease Obligations (c)	256.3	40.4	85.4	59.1	71.4
Operating Lease Obligations (d)	47.1	6.5	7.9	6.8	25.9
Purchase Obligations (e)	12,708.3	887.0	1,341.8	1,052.6	9,426.9
Other Long-Term Liabilities	989.1	101.7	199.1	198.9	489.4
Total Contractual Obligations	$ 23,101.6	$ 1,683.4	$ 2,805.3	$ 1,822.0	$ 16,790.9

(a) The amounts included in the table are calculated using current market prices, forward curves and other estimates.

(b) Principal and interest payments on Long-Term Debt (excluding capital lease obligations).

(c) Capital Lease Obligations of Wisconsin Electric for power purchase commitments.

(d) Operating Lease Obligations for power purchase commitments and rail car leases.

(e) Purchase Obligations under various contracts for the procurement of fuel, power, gas supply and associated transportation related to utility operations and for construction, information technology and other services for utility and We Power operations. This includes the power purchase agreement for Point Beach.

The table above does not include liabilities related to the accounting treatment for uncertainty in income taxes because we are not able to make a reasonably reliable estimate as to the amount and period of related future payments at this time. For additional information regarding these liabilities, refer to Note G -- Income Taxes in the Notes to Consolidated Financial Statements in this report.

Obligations for utility operations have historically been included as part of the rate-making process and therefore are generally recoverable from customers.

FACTORS AFFECTING RESULTS, LIQUIDITY AND CAPITAL RESOURCES

MARKET RISKS AND OTHER SIGNIFICANT RISKS

We are exposed to market and other significant risks as a result of the nature of our businesses and the environment in which those businesses operate. These risks, described in further detail below, include but are not limited to:

Regulatory Recovery: Our utility energy segment accounts for its regulated operations in accordance with accounting guidance for regulated entities. Our rates are determined by regulatory authorities. Our primary regulator is the PSCW. Regulated entities are allowed to defer certain costs that would otherwise be charged to expense, if the regulated entity believes the recovery of these costs is probable. We record regulatory assets pursuant to specific orders or by a generic order issued by our regulators, and recovery of these deferred costs in future rates is subject to the review and approval of those regulators. We assume the risks and benefits of ultimate recovery of these items in future rates. If the recovery of these costs is not approved by our regulators, the costs are charged to income in the current period. In general, regulatory assets are recovered in a period between one to eight years. Regulatory assets associated with pension and OPEB expenses are amortized as a component of pension and OPEB expense. Regulators can impose liabilities on a prospective basis for amounts previously collected from customers and for amounts that are expected to be refunded to customers. We record these items as regulatory liabilities. As of December 31, 2012, our regulatory assets totaled $1,380.3 million and our regulatory liabilities totaled $868.3 million.

Commodity Prices: In the normal course of providing energy, we are subject to market fluctuations of the costs of coal, natural gas, purchased power and fuel oil used in the delivery of coal. We manage our fuel and gas supply costs through a portfolio of short and long-term procurement contracts with various suppliers for the purchase of coal, natural gas and fuel oil. In addition, we manage the risk of price volatility by utilizing gas and electric hedging programs.

Wisconsin's retail electric fuel cost adjustment procedure mitigates some of Wisconsin Electric's risk of electric fuel cost fluctuation. Effective January 1, 2011, the PSCW implemented new fuel rules which allow for a deferral of prudently incurred fuel costs that fall outside of a symmetrical band (plus or minus 2%). Under the rules, any over or under-collection of fuel costs deferred at the end of the year would be incorporated into fuel cost recovery rates in future years. For information regarding the fuel rules, see Utility Rates and Regulatory Matters -- Wisconsin Fuel Rules.

Natural Gas Costs: Higher natural gas costs could increase our working capital requirements and result in higher gross receipts taxes in the state of Wisconsin. Higher natural gas costs combined with slower economic conditions also expose us to greater risks of accounts receivable write-offs as more customers are unable to pay their bills. Higher natural gas costs may also lead to increased energy efficiency investments by our customers to reduce utility usage and/or fuel substitution.

As part of its December 2012 rate order, the PSCW authorized continued use of the escrow method of accounting for bad debt costs through December 31, 2014. The escrow method of accounting for bad debt costs allows for deferral of Wisconsin residential bad debt expense that exceeds or is less than amounts allowed in rates.

As a result of GCRMs, our gas utility operations receive dollar for dollar recovery on the cost of natural gas. However, increased natural gas costs increase the risk that customers will switch to alternative fuel sources, which could reduce future gas margins. For information concerning the natural gas utilities' GCRMs, see Utility Rates and Regulatory Matters.

Weather: Our Wisconsin utility rates are set by the PSCW based upon estimated temperatures which approximate 20-year averages. Wisconsin Electric's electric revenues and sales are unfavorably sensitive to below normal temperatures during the summer cooling season, and to some extent, to above normal temperatures during the winter heating season. Our gas revenues and sales are unfavorably sensitive to above normal temperatures during the winter heating season. A summary of actual weather information in the utility segment's service territory during 2012, 2011 and 2010, as measured by degree days, may be found above in Results of Operations.

Interest Rate: We have various short-term borrowing arrangements to provide working capital and general corporate funds. We also have variable rate long-term debt outstanding as of December 31, 2012. Borrowing levels under these arrangements vary from period to period depending on capital investments and other factors. Future short-term interest expense and payments will reflect both future short-term interest rates and borrowing levels.

We performed an interest rate sensitivity analysis as of December 31, 2012 of our outstanding portfolio of commercial paper and variable rate long-term debt. As of December 31, 2012, we had $394.6 million of commercial paper outstanding with a weighted average interest rate of 0.30% and $147.0 million of variable-rate long-term debt outstanding with a weighted average interest rate of 0.50%. A one-percentage point change in interest rates would cause our annual interest expense to increase or decrease by approximately $5.4 million.

Marketable Securities Return: We use various trusts to fund our pension and OPEB obligations. These trusts invest in debt and equity securities. Changes in the market prices of these assets can affect future pension and OPEB expenses. Additionally, future contributions can also be affected by the investment returns on trust fund assets. We believe that the financial risks associated with investment returns would be partially mitigated through future rate actions by our various utility regulators.

The fair value of our trust fund assets as of December 31, 2012 was approximately:

Wisconsin Energy Corporation	Millions of Dollars	
Pension trust funds	$	1,385.4
Other post-retirement benefits trust funds	$	285.4

The expected long-term rate of return on plan assets for 2013 is 7.25% and 7.5%, respectively, for the pension and OPEB plans.

Fiduciary oversight of the pension and OPEB trust fund investments is the responsibility of an Investment Trust Policy Committee. The Committee works with external actuaries and investment consultants on an ongoing basis to establish and monitor investment strategies and target asset allocations. Forecasted cash flows for plan liabilities are regularly updated based on annual valuation results. Target asset allocations are determined utilizing projected benefit payment cash flows and risk analyses of appropriate investments. The targeted asset allocations are intended to reduce risk, provide long-term financial stability for the plans and maintain funded levels which meet long-term plan obligations while preserving sufficient liquidity for near-term benefit payments. Investment strategies utilize a wide diversification of asset types and qualified external investment managers.

We consult with our investment advisors on an annual basis to help us forecast expected long-term returns on plan assets by reviewing actual historical returns and calculating expected total trust returns using the weighted-average of long-term market returns for each of the major target asset categories utilized in the fund.

Economic Conditions: Our service territory is within the state of Wisconsin and the Upper Peninsula of Michigan. We are exposed to market risks in the regional midwest economy.

Inflation: We continue to monitor the impact of inflation, especially with respect to the costs of medical plans, fuel, transmission access, construction costs, regulatory and environmental compliance and new generation in order to minimize its effects in future years through pricing strategies, productivity improvements and cost reductions. We do not believe the impact of general inflation will have a material impact on our future results of operations.

For additional information concerning risk factors, including market risks, see the Cautionary Statement Regarding Forward-Looking Information.

POWER THE FUTURE

All of the PTF units have been placed into service and are positioned to provide a significant portion of our future generation needs. The PTF units include PWGS 1, PWGS 2, OC 1 and OC 2.

As part of our 2013 Wisconsin Rate Case, the PSCW determined that 100% of the construction costs for our Oak Creek expansion units were prudently incurred, and approved the recovery in rates of more than 99.5% of these costs. In addition, the PSCW deferred the final decision regarding $24 million related to the fuel flexibility project until a future rate proceeding. See Other Matters below for additional information about the fuel flexibility project.

We are recovering our costs in these units through lease payments associated with PWGS 1, PWGS 2, OC 1 and OC 2 that are billed from We Power to Wisconsin Electric and then recovered in Wisconsin Electric's rates as authorized by the PSCW, the Michigan Public Service Commission (MPSC) and FERC. Under the lease terms, our return is calculated using a 12.7% return on equity and the equity ratio is assumed to be 53% for the PWGS Units and 55% for the Oak Creek Units.

Wisconsin Electric operates PWGS 1, PWGS 2, OC 1 and OC 2 and is authorized by the PSCW to fully recover prudently incurred operating and maintenance costs in its Wisconsin electric rates. As the operator of the units, Wisconsin Electric may request We Power make capital improvements to or further investments in the units. Under the lease terms, we would expect the costs of any capital improvements or further investments to be added to the lease payments, and ultimately to be recovered in Wisconsin Electric's rates.

We Power assigned its warranty rights to Wisconsin Electric upon turnover of each of the Oak Creek expansion units. Although the warranty periods for both of the units have expired, Wisconsin Electric and Bechtel Power Corporation (Bechtel) continue to work through outstanding warranty claims. Wisconsin Electric's warranty claim for the costs incurred to repair steam turbine corrosion damage identified on both units is expected to be resolved through a binding arbitration hearing scheduled for October 2013.

In accordance with the contract between We Power and Bechtel, final acceptance of the units cannot occur until, among other things, all disputes have been settled. Pursuant to the settlement agreement entered into with Bechtel in December 2009, a final payment of $2.5 million per unit will be due upon final acceptance.

UTILITY RATES AND REGULATORY MATTERS

The PSCW regulates our retail electric, natural gas and steam rates in the state of Wisconsin, while FERC regulates our wholesale power, electric transmission and interstate gas transportation service rates. The MPSC regulates our retail electric rates in the state of Michigan. Within our regulated segment, we estimate that approximately 88% of our electric revenues are regulated by the PSCW, 6% are regulated by the MPSC and the balance of our electric revenues is regulated by FERC. In Wisconsin, a general rate case is typically filed every two years. All of our natural gas and steam revenues are regulated by the PSCW. Orders from the PSCW can be viewed at http://psc.wi.gov/ and orders from the MPSC can be viewed at www.michigan.gov/mpsc/.

2013 Wisconsin Rate Case: On March 23, 2012, Wisconsin Electric and Wisconsin Gas initiated rate proceedings with the PSCW. On December 20, 2012, the PSCW approved the following rate adjustments:

- A net bill increase related to non-fuel costs for Wisconsin Electric's Wisconsin retail electric customers of approximately $70 million (2.6%) for 2013. This amount reflects an offset of approximately $63 million (2.3%) related to the proceeds of a renewable energy cash grant Wisconsin Electric expects to receive under the National Defense Authorization Act (NDAA) upon completion of its biomass facility currently under construction. Absent this offset, the retail electric rate increase for non-fuel costs is approximately $133 million (4.8%) for 2013.
- Absent an adjustment for any remaining energy cash credits, an electric rate increase for Wisconsin Electric's Wisconsin electric customers of approximately $28 million (1.0%) for 2014.
- Recovery of a forecasted increase in fuel costs of approximately $44 million (1.6%) for 2013. Wisconsin Electric will make an annual fuel cost filing, as required, for 2014.
- A rate decrease of approximately $8 million (1.9%) for Wisconsin Electric's natural gas customers for 2013, with no rate adjustment in 2014.
- A rate decrease of approximately $34 million (5.5%) for Wisconsin Gas' natural gas customers for 2013, with no rate adjustment in 2014.
- An increase of approximately $1.3 million (6.0%) for Wisconsin Electric's Downtown Milwaukee (Valley) steam utility customers for 2013 and another $1.3 million (6.0%) in 2014.
- An increase of approximately $1 million (7.0%) in 2013 and $1 million (6.0%) in 2014, respectively, for Wisconsin Electric's Milwaukee County steam utility customers.

These rate adjustments were effective January 1, 2013. In addition, the PSCW indicated that Wisconsin Electric's and Wisconsin Gas' allowed return on equity would remain at 10.4% and 10.5%, respectively. The PSCW also approved escrow accounting treatment for the energy cash grant.

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

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

We received a final written order from the PSCW on November 3, 2011. For information related to the proceeding to establish a 2012 fuel cost plan, see 2012 Fuel Recovery Request below.

2012 Michigan Rate Case: On July 5, 2011, Wisconsin Electric filed a $17.5 million rate increase request with the MPSC, primarily to recover the costs of environmental upgrades and OC 2. Pursuant to Michigan law, we self-implemented a $5.7 million interim electric base rate increase in January 2012. This increase was partially offset by a refund of $2.7 million of net proceeds from Wisconsin Electric's settlement of the spent nuclear fuel litigation with the DOE, resulting in a net $3.0 million rate increase. In addition, approximately $2.0 million of renewable costs were included in our Michigan fuel recovery rate effective January 1, 2012. The MPSC approved a total increase in electric base rates of $9.2 million annually, effective June 27, 2012, and authorized a 10.1% return on equity.

2010 Wisconsin Rate Case: In March 2009, Wisconsin Electric and Wisconsin Gas initiated rate proceedings with the PSCW. In December 2009, the PSCW approved the following rate adjustments:

- An increase of approximately $85.8 million (3.35%) in retail electric rates for Wisconsin Electric, which was partially offset by bill credits in 2010;
- A decrease of approximately $2.0 million (0.35%) for natural gas service for Wisconsin Electric;
- An increase of approximately $5.7 million (0.70%) for natural gas service for Wisconsin Gas; and
- A decrease of approximately $0.4 million (1.65%) for Wisconsin Electric's Valley steam utility customers and a decrease of approximately $0.1 million (0.47%) for its Milwaukee County steam utility customers.

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

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

***2010 Michigan Rate Increase Request*:** In July 2009, Wisconsin Electric filed a $42 million rate increase request with the MPSC, primarily to recover the costs of PTF projects. In December 2009, the MPSC approved Wisconsin Electric's modified self-implementation plan to increase electric rates in Michigan by approximately $12 million, effective upon commercial operation of OC 1, which occurred on February 2, 2010. On July 1, 2010, the MPSC issued the final order, approving an additional increase of $11.5 million effective July 2, 2010. The combined total increase was $23.5 million annually, or 14.2%. In August 2010, our largest customers, two iron ore mines, filed an appeal with the MPSC regarding this rate order. In October 2010, the MPSC ruled on the mines' appeal and reduced the rate increase by approximately $0.3 million annually, effective November 1, 2010. In November 2010, the mines filed a Claim of Appeal of the October 2010 order with the Michigan Court of Appeals. In December 2010, the MPSC filed a Motion for Remand with the Court of Appeals. In March 2011, the Court of Appeals denied the Motion for Remand. All briefs have been filed and the case is awaiting scheduling of oral argument.

Limited Rate Adjustment Requests

2012 Fuel Recovery Request: In August 2011, Wisconsin Electric filed a $50 million rate increase request with the PSCW to recover forecasted increases in fuel and purchased power costs. The primary reasons for the increase were projected higher coal, coal transportation and purchased power costs. This filing was made under the new Wisconsin fuel rules which require annual fuel cost filings. In January 2012, the PSCW issued an order which provided for an increase in fuel costs of approximately $26 million, offset by approximately $26 million from the settlement with the DOE regarding the storage of spent nuclear fuel, resulting in no change in customer bills.

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

Other Utility Rate Matters

Oak Creek Air Quality Control System: 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. In March 2012, the wet flue gas desulfurization and selective catalytic reduction equipment for units 5 and 6 was placed into commercial operation. In September 2012, the equipment for units 7 and 8 was placed into commercial operation. The final cost of completing this project was approximately $740 million ($900 million including AFUDC). The cost of constructing these facilities has been included in our previous estimates of the costs to implement the Consent Decree with the United States Environmental Protection Agency (EPA).

Wisconsin Fuel Rules: Embedded within Wisconsin Electric's base rates is an amount to recover fuel costs. New fuel rules adopted in December 2010 require the company to defer, for subsequent rate recovery or refund, any under-collection or over-collection of fuel costs that are outside of the utility's symmetrical fuel cost tolerance, which the PSCW set at plus or minus 2% of the utility's approved fuel cost plan. Fuel cost plans approved by the PSCW after January 1, 2011 are subject to the new rules. The deferred fuel costs are subject to an excess revenues test.

Electric Transmission Cost Recovery: Wisconsin Electric divested its transmission assets with the formation of ATC in January 2001. We now procure transmission service from ATC at FERC approved tariff rates. In connection with the formation of ATC, our transmission costs have escalated due to the socialization of costs within ATC and increased transmission infrastructure requirements in the state. In 2002, in connection with the increased costs experienced by our customers, the PSCW issued an order which allowed us to use escrow accounting whereby we deferred transmission costs that exceeded amounts embedded in our rates. We were allowed to earn a return on the unrecovered transmission costs we deferred at our weighted-average cost of capital. As of December 31, 2012, we had $114.1 million of unrecovered transmission costs related to prior deferrals that are not subject to escrow accounting because our 2008 and 2010 PSCW rate orders provided for recovery of these costs. In the 2013 Wisconsin Rate Case, the PSCW reauthorized escrow accounting for future transmission costs and we are allowed to accrue these costs on a net of tax basis at the short-term debt rate.

Gas Cost Recovery Mechanism: Our natural gas operations operate under GCRMs as approved by the PSCW. Generally, the GCRMs allow for a dollar for dollar recovery of gas costs. The GCRMs use a modified one for one method that measures commodity purchase costs against a monthly benchmark which includes a 2% tolerance. Costs in excess of this monthly benchmark are subject to additional review by the PSCW before they can be passed through to our customers. The modified one for one is the same method used by the other utilities in Wisconsin.

Renewables, Efficiency and Conservation: In March 2006, Wisconsin revised the requirements for renewable energy generation by enacting 2005 Wisconsin Act 141 (Act 141). Act 141 defines "baseline renewable percentage" as the average of an energy provider's renewable energy percentage for 2001, 2002 and 2003. A utility's renewable energy percentage is equal to the amount of its total retail energy sales that are provided by renewable sources. Wisconsin Electric's baseline renewable energy percentage is 2.27%. Under Act 141, Wisconsin Electric could not decrease its renewable energy percentage for the years 2006-2009, and for the years 2010-2014, it must increase its renewable energy percentage at least two percentage points to a level of 4.27%. As of December 31, 2012, we are in compliance with the Wisconsin renewable energy percentage of 4.27%. Act 141 further requires that for the year 2015 and beyond, the renewable energy percentage must increase at least six percentage points above the baseline to a level of 8.27%. Act 141 established a goal that 10% of all electricity consumed in Wisconsin be generated by renewable resources by December 31, 2015. To comply with increasing requirements, Wisconsin Electric has constructed and contracted for several hundred megawatts of wind generation and is in the process of constructing approximately 50 MW of biomass fueled generation. With the commercial operation of the Glacier Hills Wind Park in December 2011, and assuming the biomass project is completed on schedule, we expect to be in compliance with Act 141's 2015 standard. We have entered into agreements for renewable energy credits which should allow us to remain in compliance with Act 141 through 2019. If market conditions are favorable, we may purchase more renewable energy credits. See Renewable Energy Portfolio discussion below for additional information regarding the development of renewable energy generation.

Act 141 allows the PSCW to delay a utility's implementation of the renewable portfolio standard if it finds that achieving the renewable requirement would result in unreasonable rate increases or would lessen reliability, or that new renewable projects could not be permitted on a timely basis or could not be served by adequate transmission facilities. Act 141 provides that if a utility is in compliance with the renewable energy and energy efficiency requirements as determined by the PSCW, then the utility may not be ordered to achieve additional energy conservation or efficiency.

Act 141 also redirects the administration of energy efficiency, conservation and renewable programs from the Wisconsin Department of Administration back to the PSCW and/or contracted third parties. In addition, Act 141 required that 1.2% of utilities' annual operating revenues be used to fund these programs in 2012. The funding required by Act 141 for 2013 is also 1.2% of annual operating revenues.

Public Act 295 enacted in Michigan requires 10% of the state's energy to come from renewables by 2015 and energy optimization (efficiency) targets up to 1% annually by 2015. Public Act 295 specifically calls for current recovery of costs incurred to meet the standards and provides for ongoing review and revision to assure the measures taken are cost-effective.

Renewable Energy Portfolio: The Blue Sky Green Field wind farm project, which has 88 turbines with an installed capacity of 145 MW, commenced commercial operation in May 2008. The Glacier Hills Wind Park, which has 90 turbines with an installed capacity of 162 MW, commenced commercial operation in December 2011. The final cost of the Glacier Hills Wind Park is approximately $347 million, excluding AFUDC.

We are constructing a biomass-fueled power plant at Domtar Corporation's Rothschild, Wisconsin paper mill site. Wood waste and wood shavings will be used to produce approximately 50 MW of renewable electricity and will also support Domtar's sustainable papermaking operations. Construction commenced in June 2011. We currently expect to invest between $245 million and $255 million, excluding AFUDC, in the plant. We are targeting completion of the facility by the end of 2013.

On December 21, 2012, we purchased Montfort Wind Energy Center (Montfort) from NextEra Energy Resources for $27 million. Montfort has 20 turbines with an installed capacity of 30 MW.

ELECTRIC SYSTEM RELIABILITY

We continue to upgrade our electric distribution system, including substations, transformers and lines. We had adequate capacity to meet all of our firm electric load obligations during 2012 and 2011. All of our generating plants performed as expected during the warmest periods of the summer and all power purchase commitments under firm contract were received. During this period, public appeals for conservation were not required and we did not interrupt or curtail service to non-firm customers who participate in load management programs. We expect to have adequate capacity to meet all of our firm load obligations during 2013. However, extremely hot weather, unexpected equipment failure or unavailability could require us to call upon load management procedures.

ENVIRONMENTAL MATTERS

Overview

Consistent with other companies in the energy industry, we face significant ongoing environmental compliance and remediation obligations related to current and past operations. Specific environmental issues affecting our utility and non-utility energy segments include but are not limited to current and future regulation of: (1) air emissions such as Sulfur Dioxide (SO_2), Nitrogen Oxide (NO_x), fine particulates, mercury and greenhouse gas emissions; (2) water discharges; (3) disposal of coal combustion by-products such as fly ash; and (4) remediation of impacted properties, including former manufactured gas plant sites.

We are continuing to pursue a proactive strategy to manage our environmental compliance obligations, including: (1) developing additional sources of renewable electric energy supply; (2) reviewing water quality matters such as discharge limits and cooling water requirements and implementing improvements to our cooling water intake systems as needed; (3) adding emission control equipment to existing facilities to comply with new ambient air quality standards and federal clean air rules; (4) implementing a Consent Decree with the EPA to reduce emissions of SO_2 and NO_x by more than 65% by 2013; (5) converting the fuel source for VAPP from coal to natural gas; (6) continuing the beneficial use of ash and other solid products from coal-fired generating units; and (7) conducting the clean-up of former manufactured gas plant sites.

Air Quality

EPA Consent Decree: In April 2003, Wisconsin Electric reached a Consent Decree with the EPA, in which it agreed to significantly reduce air emissions from certain of its coal-fired generating facilities. The U.S. District Court for the Eastern District of Wisconsin approved the amended Consent Decree and entered it in October 2007. For further information, see Note P -- Commitments and Contingencies in the Notes to Consolidated Financial Statements.

National Ambient Air Quality Standards (NAAQS)

8-hour Ozone Standards: In April 2004, the EPA designated 10 counties in southeastern Wisconsin as non-attainment areas for the 1997 8-hour ozone ambient air quality standard. The EPA has since redesignated all of these counties to attainment. In 2008, the EPA issued an additional, more stringent 8-hour ozone standard, and made final attainment designations for this revised standard in 2012. In April 2012 and May 2012, the EPA designated Sheboygan County and the eastern portion of Kenosha County, respectively, as 2008 8-hour ozone standard non-attainment areas. The net result of all of these actions is that construction permitting for all of our Wisconsin power plants, except the Pleasant Prairie Power Plant, is expected to be subject to less stringent permitting requirements. In addition, modifications to these facilities should no longer be required to obtain emission offsets. The Pleasant Prairie Power Plant will continue to be subject to more stringent permitting requirements and offset provisions.

In January 2010, the EPA announced its decision to further lower the 2008 8-hour ozone standard. However, in September 2011, President Obama requested the EPA to delay the reconsideration of the 8-hour ozone standard until 2013.

Fine Particulate Standard: In 2009, the EPA designated three counties in southeast Wisconsin (Milwaukee, Waukesha and Racine) as not meeting the daily standard for Fine Particulate Matter ($PM_{2.5}$). In April 2012, the EPA proposed to determine that these three counties meet the $PM_{2.5}$ standard, and proposed to suspend the requirement that the state submit a State Implementation Plan (SIP) including reasonably available control technology (RACT) regulations. On December 28, 2012, the EPA re-proposed this determination along with further clarification of its authority to suspend RACT and other SIP requirements. Until the EPA finalizes this action and redesignates the three counties to attainment, our generating facilities in the non-attainment counties will continue to be subject to more stringent construction permitting requirements and emission offset provisions. On December 14, 2012, the EPA issued a revised and more stringent annual $PM_{2.5}$ standard. Current monitored air quality data indicates that all areas of Wisconsin and Michigan's Upper Peninsula meet the revised standard. Although we do not expect the lower standard to impose any additional requirements on our operations, until the EPA develops a rule or guidance that dictates implementation of the new standard, we are unable to predict how these actions may affect any future construction permitting activities.

Sulfur Dioxide Standard: In June 2010, the EPA issued new hourly SO_2 NAAQS that became effective in August 2010. These standards, as modified, represent a significant change from the previous SO_2 standards. The implementation guidance for the new standards, among other things, required attainment designations to be based on modeling rather than monitoring. Traditionally, attainment designations were based on monitored data. The EPA has since withdrawn this implementation guidance, and has indicated it is going to propose new implementation guidance through a rulemaking in 2013.

Various parties have submitted judicial and administrative challenges to this rule, and litigation is pending in the U.S. Court of Appeals for the D.C. Circuit challenging, among other things, the stringency of the standards and the EPA's plans to require attainment designations to be based on modeling.

If the new standards remain in place, we believe that we would not need to make significant capital expenditures at the majority of our generation units because of prior investments in pollution control equipment and technology. However, we believe that the new standards will require us to retrofit Presque Isle Power Plant (PIPP) in the Upper Peninsula of Michigan with additional environmental controls. In November 2012, we entered into a joint ownership agreement with Wolverine Power Supply Cooperative, Inc. (Wolverine) whereby Wolverine will pay for the installation of air quality control systems at PIPP and will receive a minority ownership interest in the plant in return. This transaction is subject to the receipt of regulatory approvals from various state and federal regulatory agencies, including the MPSC, PSCW and FERC. We began submitting applications for these regulatory approvals in February 2013.

The new standards may also require us to make modifications at some of our smaller generation units.

Nitrogen Dioxide Standard: In January 2010, the EPA announced a new hourly Nitrogen Dioxide standard, which became effective in April 2010. We are unable to predict the impact on the operation of our generation facilities until final attainment designations are made and until any potential additional rules are adopted.

Mercury and Other Hazardous Air Pollutants: In December 2011, the EPA issued the final Mercury and Air Toxics Standard (MATS) rule, which imposes stringent limitations on numerous hazardous air pollutants, including mercury, from coal and oil-fired electric generating units. While we are continuing to evaluate the impact of the rule on the operation of our existing coal-fired generation facilities, as well as alternatives for complying with the rule, we currently estimate our capital cost to comply with this rule will be approximately $8.0 million to $12.5 million. Based upon our review of the rules and plans to convert the VAPP from coal to natural gas fuel, we currently anticipate that only the PIPP will require modifications, which we expect will be funded by Wolverine under the joint ownership agreement. We believe that our clean air strategy, including the environmental upgrades that have been constructed and that are currently under construction at our other coal-fired plants, positions those other plants well to meet the rule's requirements.

Cross-State Air Pollution Rule: In August 2011, the EPA issued the Cross-State Air Pollution Rule (CSAPR), formerly known as the Clean Air Transport Rule. This rule was proposed in 2010 to replace the Clean Air Interstate Rule (CAIR), which had been remanded to the EPA in 2008. The stated purpose of the CSAPR is to limit the interstate transport of emissions of NO_x and SO_2 that contribute to fine particulate matter and ozone non-attainment in downwind states through a proposed allocation scheme. In February 2012, the EPA issued final technical revisions to the rule and issued a draft final rule which together delay the implementation date for certain penalty provisions that could potentially impact the PIPP and increase the number of allowances issued to the states of Michigan and Wisconsin. Even with these proposed revisions, however, the PIPP may not have been allocated sufficient allowances to meet its obligations to operate and provide stability to the transmission system in the Upper Peninsula of Michigan. This situation could then put the plant at risk for certain penalties under the rule.

The rule was scheduled to become effective January 1, 2012. However, we and a number of other parties sought judicial review of the rule, and in August 2012, the U.S. Court of Appeals for the District of Columbia Circuit vacated the CSAPR, keeping the CAIR in effect. The EPA had requested the court to re-hear the case; however, on January 24, 2013, the court denied the EPA's request. The EPA has 90 days from the date of the D.C. Circuit Court's decision to appeal to the United States Supreme Court.

Wisconsin and Michigan Mercury Rules: Both Wisconsin and Michigan have mercury rules that require a 90% reduction of mercury. We have plans in place to comply with those requirements and the costs of these plans are incorporated in our capital and operation and maintenance costs.

Clean Air Visibility Rule: The EPA issued the Clean Air Visibility Rule in June 2005 to address Regional Haze, or regionally-impaired visibility caused by multiple sources over a wide area. The rule defines Best Available Retrofit Technology (BART) requirements for electric generating units and how BART will be addressed in the 28 states subject to the EPA's CAIR. The pollutants from power plants that reduce visibility include $PM_{2.5}$ or compounds that contribute to fine particulate formation, NO_x, SO_2 and ammonia.

In June 2012, the EPA promulgated a Federal Implementation Plan that approves reliance on the CSAPR to satisfy electric generating unit BART requirements for NO_x and SO_2. In December 2012, the EPA approved the remainder of Michigan's regional haze SIP. In August 2012, the EPA approved Wisconsin's regional haze SIP, which also relies on the CSAPR to satisfy electric generating unit BART requirements for NO_x and SO_2.

Because of the court decision to vacate CSAPR and potential continuing litigation on that decision, we will not be able to determine final regional haze requirements for NO_x and SO_2 at our facilities until judicial review of CSAPR is completed and any subsequent rulemaking activities required as a result of that review have been finalized.

Climate Change: We continue to take measures to reduce our emissions of greenhouse gases. We support flexible, market-based strategies to curb greenhouse gas emissions, including emissions trading, joint implementation projects and credit for early actions. We support an approach that encourages technology development and transfer and includes all sectors of the economy and all significant global emitters. We have taken, and continue to take, several steps to reduce our emissions of greenhouse gases, including:

- Repowering the Port Washington Power Plant from coal to natural gas-fired combined cycle units.
- Adding coal-fired units as part of the Oak Creek expansion that are the most thermally efficient coal units in our system.
- Increasing investment in energy efficiency and conservation.
- Adding renewable capacity and continuing to offer the Energy for Tomorrow® renewable energy program.
- Planning to convert the fuel source at the VAPP from coal to natural gas.
- Retirement of coal units 1-4 at the Presque Isle Power Plant.

Federal, state, regional and international authorities have undertaken efforts to limit greenhouse gas emissions. The President's administration recently reaffirmed that regulation of greenhouse gas emissions continues to be a top priority. Although legislation that would impose mandatory requirements related to greenhouse gas emissions, renewable energy standards and/or energy efficiency standards failed to pass in the U.S. Congress, we expect such legislation to be considered in the future. Any mandatory restrictions on our Carbon Dioxide (CO_2) emissions that may be adopted by Congress or Wisconsin's or Michigan's legislature could result in significant compliance costs that could affect future results of operations, cash flows and financial condition.

While climate change legislation has yet to be adopted, the EPA is pursuing regulation of greenhouse gas emissions using its existing authority under the Clean Air Act (CAA). In March 2012, the EPA proposed new source performance standards pertaining to greenhouse gas emissions from certain new power plants, including coal-fired plants, based on the performance of combined cycle natural gas-fueled generating plants.

We expect the EPA to attempt to address performance standards for existing generating units in 2013. Any such regulations may impact how we operate our existing facilities. Depending on the extent of rate recovery and other factors, these anticipated future rules could have a material adverse impact on our financial condition.

We are required to report our CO_2 equivalent emissions from our electric generating facilities to the EPA under its Mandatory Reporting of Greenhouse Gases rule. For 2011, we reported CO_2 equivalent emissions of approximately 22.4 million metric tonnes to the EPA, compared with approximately 20.9 million metric tonnes for 2010. Based upon our preliminary analysis of the monitoring data, we estimate that we will report CO_2 equivalent emissions of approximately 18.1 million metric tonnes to the EPA for 2012. The level of CO_2 and other greenhouse gas emissions vary from year to year and are dependent on the level of electric generation and mix of fuel sources, which is determined primarily by demand, the availability of the generating units, the unit cost of fuel consumed and how our units are dispatched by MISO.

We are also required to report CO_2 amounts related to the natural gas our gas utility distributes and sells. For 2011, we reported approximately 9.5 million metric tonnes of CO_2 to the EPA related to our distribution and sale of natural gas, compared with approximately 9.0 million metric tonnes for 2010. Based upon our preliminary analysis of the monitoring data, we estimate that we will report CO_2 emissions of approximately 8.4 million metric tonnes to the EPA for 2012.

Valley Power Plant Conversion: In August 2012, we announced plans to convert the fuel source for VAPP from coal to natural gas. We currently expect the cost of this conversion to be between $60 million and $65 million and, subject to receipt of PSCW approval and a construction air permit from the Wisconsin Department of Natural Resources (WDNR), anticipate that the conversion will be completed by the end of 2015 or early 2016. We expect to file for a Certificate of Authority from the PSCW during the second quarter of 2013.

In June 2012, we received approval from the PSCW to replace and upgrade the Lincoln Arthur natural gas main, which has the capability to accommodate the increased natural gas required for the conversion of VAPP to natural gas. For further information, see Note P -- Commitments and Contingencies in the Notes to Consolidated Financial Statements.

Water Quality

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

The EPA proposed a new Phase II rule in 2011, which must be finalized by June 27, 2013. Once the rule is final, it will apply to all of our existing generating facilities with cooling water intake structures other than the Oak Creek expansion, which was permitted under the Phase I rules.

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

The EPA has proposed that the BTA for entrainment mortality reduction be determined on a case-by-case basis. Therefore, permitting agencies would be required to determine BTA with respect to entrainment on a site-specific basis taking into consideration several factors. Because the entrainment reduction standard is a site-specific determination, we cannot yet determine what, if any, intake structure or operational modifications will be required to meet this proposed requirement.

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

On December 27, 2012, the WDNR issued a new Wisconsin Pollutant Discharge Elimination System (WPDES) permit for VAPP that became effective on January 1, 2013. The new permit includes significant new immediate and long-term permit requirements. Effluent toxicity testing and monitoring for additional parameters (phosphorous, mercury and ammonia-nitrogen), and a new heat addition limit from the cooling water discharges all took effect immediately. Longer term compliance requirements include thermal discharge studies, phosphorous evaluation and feasibility for reduction, mercury minimization planning, and redesign of the cooling water intakes to minimize impingement impacts to aquatic organisms.

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

Land Quality

Proposed New Coal Combustion Products Regulation: We currently have a program of beneficial utilization for substantially all of our coal combustion products, including fly ash, bottom ash and gypsum, which minimizes the need for disposal in specially-designed landfills. Both Wisconsin and Michigan have regulations governing the use and disposal of these materials. In 2010, the EPA issued draft rules for public comment proposing two alternative rules for regulating coal combustion products, one of which would classify the materials as hazardous waste. We anticipate the earliest the EPA will take action on a final rule is the first quarter of 2014. If coal combustion products are classified as hazardous waste, it could have a material adverse effect on our ability to continue our current program.

If coal combustion products are classified as hazardous waste and we terminate our coal combustion products utilization program, we could be required to dispose of the coal combustion products at a significant cost to the Company, which could adversely impact our results of operations and financial condition.

In addition, the EPA finalized the Commercial and Industrial Solid Waste Incineration Units rule under the CAA, as well as the Non-Hazardous Secondary Materials Rule. We are continuing to pursue an EPA determination on acceptable use for coal ash as a non-hazardous secondary material based on our processing of the materials prior to reburning as currently allowed under the Secondary Materials Rule. Both of these rules have the potential to negatively affect our ability to reburn coal ash from power plants and landfills.

Manufactured Gas Plant Sites: We continue to voluntarily review and address environmental conditions at a number of former manufactured gas plant sites. For further information, see Note P -- Commitments and Contingencies in the Notes to Consolidated Financial Statements.

Ash Landfill Sites: We aggressively seek environmentally acceptable, beneficial uses for our combustion byproducts. For further information, see Note P -- Commitments and Contingencies in the Notes to Consolidated Financial Statements.

LEGAL MATTERS

Cash Balance Pension Plan: See Note P -- Commitments and Contingencies in the Notes to Consolidated Financial Statements for information regarding a lawsuit filed against the Wisconsin Energy Corporation Retirement Account Plan (Plan).

Stray Voltage: On July 11, 1996, the PSCW issued a final order regarding the stray voltage policies of Wisconsin's investor-owned utilities. The order clarified the definition of stray voltage, affirmed the level at which utility action is required, and placed some of the responsibility for this issue in the hands of the customer. Additionally, the order established a uniform stray voltage tariff which delineates utility responsibility and provides for the recovery of costs associated with unnecessary customer demanded services.

Dairy farmers continue to make claims against Wisconsin Electric for loss of milk production and other damages to livestock allegedly caused by stray voltage and ground currents resulting from the operation of its electrical system, even though that electrical system has been operated within the parameters of the PSCW's order. The Wisconsin Supreme Court has rejected the arguments that, if a utility company's measurement of stray voltage is below the PSCW "level of concern," that utility could not be found negligent in stray voltage cases. Additionally, the Court has held that the PSCW regulations regarding stray voltage were only minimum standards to be considered by a jury in stray voltage litigation. As a result of these rulings, claims by dairy farmers for livestock damage have been based upon ground currents with levels measuring less than the PSCW "level of concern." We continue to evaluate various options and strategies to mitigate this risk.

NUCLEAR OPERATIONS

Used Nuclear Fuel Storage and Disposal: During Wisconsin Electric's ownership of Point Beach, Wisconsin Electric was authorized by the PSCW to load and store sufficient dry fuel storage containers to allow Point Beach Units 1 and 2 to operate to the end of their original operating licenses, but not to exceed the original 48-canister capacity of the dry fuel storage facility. The original operating licenses were set to expire in October 2010 for Unit 1 and in March 2013 for Unit 2 before they were renewed and extended by the United States Nuclear Regulatory Commission in December 2005.

Temporary storage alternatives at Point Beach are necessary until the DOE takes ownership of and permanently removes the used fuel as mandated by the Nuclear Waste Policy Act of 1982, as amended in 1987. The Nuclear Waste Policy Act established the Nuclear Waste Fund which is composed of payments made by the generators and owners of such waste and fuel. Effective January 31, 1998, the DOE failed to meet its contractual obligation to begin removing used fuel from Point Beach, a responsibility for which Wisconsin Electric paid a total of $215.2 million into the Nuclear Waste Fund over the life of its ownership of Point Beach.

In August 2000, the United States Court of Appeals for the D.C. Circuit ruled in a lawsuit brought by Maine Yankee and Northern States Power Company that the DOE's failure to begin performance by January 31, 1998 constituted a breach of the Standard Contract, providing clear grounds for filing complaints in the Court of Federal Claims. Consequently, Wisconsin Electric filed a complaint in November 2000 against the DOE in the Court of Federal Claims. In October 2004, the Court of Federal Claims granted Wisconsin Electric's motion for summary judgment on liability. The Court held a trial during September and October 2007 to determine damages. In December 2009, the Court ruled in favor of Wisconsin Electric, granting us more than $50 million in damages. In February 2010, the DOE filed an appeal. We negotiated a settlement with the DOE for $45.5 million, which we received in the first quarter of 2011. This amount, net of costs incurred, was returned to customers as part of the PSCW's approval of our 2012 fuel recovery request and the MPSC's approval of our interim order for the 2012 Michigan rate case.

INDUSTRY RESTRUCTURING AND COMPETITION

Electric Utility Industry

The regulated energy industry continues to experience significant changes. FERC continues to support large Regional Transmission Organizations (RTO), which affect the structure of the wholesale market. To this end, the MISO implemented bid-based markets, the MISO Energy Markets, including the use of Locational Margin Price (LMP) to value electric transmission congestion and losses. The MISO Energy Markets commenced operation in April 2005 for energy distribution and in January 2009 for operating reserves. Increased competition in the retail and wholesale markets, which may result from restructuring efforts, could have a significant and adverse financial impact on us. It is uncertain when retail access might be implemented, if at all, in Wisconsin; however, Michigan has adopted retail choice which potentially affects our Michigan operations.

Restructuring in Wisconsin: Electric utility revenues in Wisconsin are regulated by the PSCW. Due to many factors, including relatively competitive electric rates charged by the state's electric utilities, the PSCW has been focused on electric reliability infrastructure issues for the state of Wisconsin in recent years.

The PSCW continues to maintain the position that the question of whether to implement electric retail competition in Wisconsin should ultimately be decided by the Wisconsin legislature. No such legislation has been introduced in Wisconsin to date.

Restructuring in Michigan: Our Michigan retail customers are allowed to remain with their regulated utility at regulated rates or choose an alternative electric supplier to provide power supply service. We have maintained our generation capacity and distribution assets and provide regulated service as we have in the past. We continue providing distribution and customer service functions regardless of the customer's power supplier.

Competition and customer switching to alternative suppliers in our service territories in Michigan has been limited. However, the additional competitive pressures resulting from retail access could lead to a loss of customers and our incurring stranded costs. A loss of customers could also have a material adverse effect on our results of operations and cash flows.

Electric Transmission and Energy Markets

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 an 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 Load Serving Entities located in the service territories of each MISO transmission owner. FERC has previously confirmed the use of the current transmission cost allocation methodology. Certain additional costs for new transmission projects are allocated throughout the MISO footprint.

We, along with others, have sought rehearing and/or appeal of the FERC's various Revenue Sufficiency Guarantee orders related to the determination that MISO had applied its energy markets tariff correctly in the assessment of the charges. The net effects of any final determination by FERC or the courts are uncertain at this time.

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 Auction Revenue Rights (ARRs) and Financial Transmission Rights (FTRs). ARRs are allocated to market participants by MISO and FTRs are purchased through auctions. A new allocation and auction were completed for the period of June 1, 2012 through May 31, 2013. The resulting ARR valuation and the secured FTRs are expected to mitigate our transmission congestion risk for that period.

Natural Gas Utility Industry

Restructuring in Wisconsin: The PSCW previously instituted generic proceedings to consider how its regulation of gas distribution utilities should change to reflect the changing competitive environment in the natural gas industry. To date, the PSCW has made a policy decision to deregulate the sale of natural gas in customer segments with workably competitive market choices and has adopted standards for transactions between a utility and its gas marketing affiliates. However, work on deregulation of the gas distribution industry by the PSCW continues to be on hold. Currently, we are unable to predict the impact of potential future deregulation on our results of operations or financial position.

OTHER MATTERS

Oak Creek Expansion Fuel Flexibility Project: The Oak Creek expansion units were designed and permitted to use bituminous coal from the Eastern United States. Market forces have resulted in a significant price differential between bituminous and sub-bituminous coals. We recently received a new air construction permit from the WDNR to modify the Oak Creek expansion units for potential future use of sub-bituminous coal. We are scheduled to begin testing sub-bituminous coal in various combinations with bituminous coal in 2013 to identify any equipment limitations that should be considered prior to filing with the PSCW for a Certificate of Authority to make the fuel flexibility modifications. In February 2013, the Sierra Club and the Midwest Environmental Defense Center filed for a contested case hearing with the WDNR to challenge the issuance of the air construction permit.

***Paris Generating Station Units 1 and 4 Temporary Outage*:** Between 2000 and 2002, we replaced the blades on the four Paris Generating Station (PSGS) combustion turbine generators with blades that were approximately 7% more efficient. Although the work was performed as routine maintenance that we did not believe required a construction permit at the time and the plant has not been operated to use the potential additional capacity, the WDNR has indicated that it now considers this maintenance to be a modification requiring a construction permit. The WDNR issued a Notice of Violation (NOV) to Wisconsin Electric on January 7, 2013 alleging violations of the new source review rules and certain Wisconsin environmental rules. At the same time, the WDNR also issued an administrative order that prohibits us from operating PSGS Units 1 and 4 until the earlier of: (1) Units 1 and 4 achieve the applicable NO_x emission rates; (2) the Wisconsin regulations are revised so that Units 1 and 4 can achieve the emission limits or are no longer subject to the limits; (3) the alleged modification is resolved through a consent decree; or (4) until a court decides that the blade replacement project was not a major modification. We are presently evaluating alternative approaches to return these peaking units to service, and expect that Units 1 and 4 will remain out of service until at least 2014. In addition, we may be subject to fines and penalties. In February 2013, the Sierra Club filed for a contested case hearing with the WDNR in connection with the administrative order.

We continue to evaluate the impact, if any, that this outage may have on network reliability, and to determine whether we will need to find alternative sources of generation in the short-term to replace the generation from these units during the temporary outage.

PSGS Units 2 and 3 remain available for operation, because the turbine blade maintenance on these units occurred prior to a rule change in 2001.

ACCOUNTING DEVELOPMENTS

New Pronouncements: See Note B -- Recent Accounting Pronouncements in the Notes to Consolidated Financial Statements in this report for information on new accounting pronouncements.

Section 1603 Renewable Energy Treasury Grant: We expect to receive a treasury grant of approximately $72 million related to the construction of our biomass facility in Rothschild, Wisconsin. We expect to recognize the treasury grant when the plant is placed into service, which is when we expect to conclude it is probable we will receive the grant and when we can reasonably estimate the grant amount. The expected receipt of the treasury grant has been taken into consideration by the PSCW in connection with our electric rates that became effective January 1, 2013. Our Wisconsin retail electric customers will receive bill credits in 2013 and 2014 related to the treasury grant. When we recognize the treasury grant as income, we will also defer a portion of the grant associated with the future bill credits and the deferred grant will be amortized to income to match the bill credits to the customers.

International Financial Reporting Standards: During 2009, the SEC announced a "roadmap" for the potential use by U.S. registrants of IFRS instead of GAAP. The SEC issued a Work Plan to consider specific areas and factors relevant to a determination of whether, when and how the current financial reporting system for U.S. registrants should be transitioned to a system incorporating IFRS. In July 2012, the SEC Staff issued its final report on the Work Plan. The report does not include a final policy or decision as to whether IFRS might be incorporated into the financial reporting system for U.S. registrants, or how such incorporation should occur. The Staff report indicates that additional analysis is necessary before any SEC decision is made about incorporating IFRS into the U.S. financial reporting system. The timing of this additional activity is currently unknown. To the extent the SEC determines to adopt IFRS, if at all, we are currently unable to determine when we would be required to begin using IFRS.

CRITICAL ACCOUNTING ESTIMATES

Preparation of financial statements and related disclosures in compliance with GAAP requires the application of appropriate technical accounting rules and guidance, as well as the use of estimates. The application of these policies necessarily involves judgments regarding future events, including the likelihood of success of particular projects, legal and regulatory challenges and anticipated recovery of costs. These judgments, in and of themselves, could materially impact the financial statements and disclosures based on varying assumptions. In addition, the financial and operating environment may also have a significant effect, not only on the operation of our business, but on our results reported through the application of accounting measures used in preparing the financial statements and related disclosures, even if the nature of the accounting policies applied have not changed.

The following is a list of accounting policies that are most significant to the portrayal of our financial condition and results of operations and that require management's most difficult, subjective or complex judgments:

Regulatory Accounting: Our utility subsidiaries operate under rates established by state and federal regulatory commissions which are designed to recover the cost of service and provide a reasonable return to investors. The actions of our regulators may allow us to defer costs that non-regulated entities would expense and accrue liabilities that non-regulated companies would not. As of December 31, 2012, we had $1,380.3 million in regulatory assets and $868.3 million in regulatory liabilities. In the future, if we move to market based rates, or if the actions of our regulators change, we may conclude that we are unable to follow regulatory accounting.

In this situation, we would record the regulatory assets related to unrecognized pension and OPEB costs as a reduction of equity, after tax. The balance of our regulatory assets net of regulatory liabilities would be recorded as an extraordinary after-tax non-cash charge to earnings. We continually review the applicability of regulatory accounting and have determined that it is currently appropriate to continue following it. In addition, each quarter we perform a review of our regulatory assets and our regulatory environment and we evaluate whether we believe that it is probable that we will recover the regulatory assets in future rates. See Note C -- Regulatory Assets and Liabilities in the Notes to Consolidated Financial Statements for additional information.

Pension and OPEB: Our reported costs of providing non-contributory defined pension benefits (described in Note M -- Benefits in the Notes to Consolidated Financial Statements) are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience. Pension costs are impacted by actual employee demographics (including age, compensation levels and employment periods), the level of contributions made to plans and earnings on plan assets. Changes made to the provisions of the plans may also impact current and future pension costs. Pension costs may also be significantly affected by changes in key actuarial assumptions, including anticipated rates of return on plan assets and the discount rates used in determining the projected benefit obligation and pension costs.

Changes in pension obligations associated with these factors may not be immediately recognized as pension costs on the income statement, but generally are recognized in future years over the remaining average service period of plan participants. As such, significant portions of pension costs recorded in any period may not reflect the actual level of cash benefits provided to plan participants.

The following table reflects pension plan sensitivities associated with changes in certain actuarial assumptions by the indicated percentage. Each sensitivity reflects a change to the given assumption, holding all other assumptions constant.

Pension Plan Actuarial Assumption	Impact on Annual Cost (Millions of Dollars)
0.5% decrease in discount rate and lump sum conversion rate	$ 4.8
0.5% decrease in expected rate of return on plan assets	$ 6.2

In addition to pension plans, we maintain OPEB plans which provide health and life insurance benefits for retired employees (described in Note M -- Benefits in the Notes to Consolidated Financial Statements). Our reported costs of providing these post-retirement benefits are dependent upon numerous factors resulting from actual plan experience including employee demographics (age and compensation levels), our contributions to the plans, earnings on plan assets and health care cost trends. Changes made to the provisions of the plans may also impact current and future OPEB costs. OPEB costs may also be significantly affected by changes in key actuarial assumptions, including anticipated rates of return on plan assets and the discount rates used in determining the OPEB and post-retirement costs. Our OPEB plan assets are primarily made up of equity and fixed income investments. Fluctuations in actual equity market returns, as well as changes in general interest rates, may result in increased or decreased other post-retirement costs in future periods. Similar to accounting for pension plans, the regulators of our utility segment have adopted accounting guidance for compensation related to retirement benefits for rate-making purposes.

The following table reflects OPEB plan sensitivities associated with changes in certain actuarial assumptions by the indicated percentage. Each sensitivity reflects a change to the given assumption, holding all other assumptions constant.

OPEB Plan Actuarial Assumption	Impact on Annual Cost (Millions of Dollars)
0.5% decrease in discount rate	$ 2.5
0.5% decrease in health care cost trend rate in all future years	$ (3.3)
0.5% decrease in expected rate of return on plan assets	$ 1.3

Unbilled Revenues: We record utility operating revenues when energy is delivered to our customers. However, the determination of energy sales to individual customers is based upon the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of their last meter reading are estimated and corresponding unbilled revenues are calculated. This unbilled revenue is estimated each month based upon actual generation and throughput volumes, recorded sales, estimated customer usage by class, weather factors, estimated line losses and applicable customer rates. Significant fluctuations in energy demand for the unbilled period or changes in the composition of customer classes could impact the accuracy of the unbilled revenue estimate. Total utility operating revenues during 2012 of approximately $4.2 billion included accrued utility revenues of $278.1 million as of December 31, 2012.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See 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 this report, as well as Note K -- Derivative Instruments and Note L -- Fair Value Measurements in the Notes to Consolidated Financial Statements, for information concerning potential market risks to which Wisconsin Energy and its subsidiaries are exposed.

WISCONSIN ENERGY CORPORATION
CONSOLIDATED INCOME STATEMENTS

Year Ended December 31

	2012	2011	2010
	(Millions of Dollars, Except Per Share Amounts)		
Operating Revenues	$ 4,246.4	$ 4,486.4	$ 4,202.5
Operating Expenses			
Fuel and purchased power	1,098.6	1,169.7	1,099.9
Cost of gas sold	545.8	728.7	751.5
Other operation and maintenance	1,116.1	1,256.8	1,327.5
Depreciation and amortization	364.2	330.2	305.6
Property and revenue taxes	121.4	113.7	106.0
Total Operating Expenses	3,246.1	3,599.1	3,590.5
Amortization of Gain	—	—	198.4
Operating Income	1,000.3	887.3	810.4
Equity in Earnings of Transmission Affiliate	65.7	62.5	60.1
Other Income and Deductions, net	34.8	62.7	40.2
Interest Expense, net	248.2	235.8	206.4
Income from Continuing Operations Before Income Taxes	852.6	776.7	704.3
Income Tax Expense	306.3	263.9	249.9
Income from Continuing Operations	546.3	512.8	454.4
Income from Discontinued Operations, Net of Tax	—	13.4	2.1
Net Income	$ 546.3	$ 526.2	$ 456.5
Earnings Per Share (Basic)			
Continuing Operations	$ 2.37	$ 2.20	$ 1.94
Discontinued Operations	—	0.06	0.01
Total Earnings Per Share (Basic)	$ 2.37	$ 2.26	$ 1.95
Earnings Per Share (Diluted)			
Continuing Operations	$ 2.35	$ 2.18	$ 1.92
Discontinued Operations	—	0.06	0.01
Total Earnings Per Share (Diluted)	$ 2.35	$ 2.24	$ 1.93
Weighted Average Common Shares Outstanding (Millions)			
Basic	230.2	232.6	233.8
Diluted	232.8	235.4	236.7

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

WISCONSIN ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS

December 31

ASSETS

	2012	2011
	(Millions of Dollars)	
Property, Plant and Equipment		
In service	$ 14,238.8	$ 12,977.7
Accumulated depreciation	(4,036.0)	(3,797.8)
	10,202.8	9,179.9
Construction work in progress	315.9	921.3
Leased facilities, net	53.5	59.2
Net Property, Plant and Equipment	10,572.2	10,160.4
Investments		
Equity investment in transmission affiliate	378.3	349.7
Other	35.5	43.6
Total Investments	413.8	393.3
Current Assets		
Cash and cash equivalents	35.6	14.1
Restricted cash	2.7	45.5
Accounts receivable, net of allowance for doubtful accounts of $58.0 and $61.7	285.3	349.4
Income taxes receivable	98.1	155.1
Accrued revenues	278.1	252.7
Materials, supplies and inventories	360.7	382.0
Prepayments	145.5	140.3
Other	107.9	87.1
Total Current Assets	1,313.9	1,426.2
Deferred Charges and Other Assets		
Regulatory assets	1,339.0	1,238.7
Goodwill	441.9	441.9
Other	204.2	201.6
Total Deferred Charges and Other Assets	1,985.1	1,882.2
Total Assets	$ 14,285.0	$ 13,862.1

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

WISCONSIN ENERGY CORPORATION
CONSOLIDATED BALANCE SHEETS

December 31

CAPITALIZATION AND LIABILITIES

	2012	2011
	(Millions of Dollars)	
Capitalization		
Common equity	$ 4,135.1	$ 3,963.3
Preferred stock of subsidiary	30.4	30.4
Long-term debt	4,453.8	4,614.3
Total Capitalization	8,619.3	8,608.0
Current Liabilities		
Long-term debt due currently	412.1	32.6
Short-term debt	394.6	669.9
Accounts payable	368.4	325.7
Accrued payroll and benefits	100.9	105.9
Other	167.3	230.4
Total Current Liabilities	1,443.3	1,364.5
Deferred Credits and Other Liabilities		
Regulatory liabilities	866.5	902.0
Deferred income taxes - long-term	2,117.0	1,696.1
Deferred revenue, net	709.7	754.5
Pension and other benefit obligations	244.0	222.7
Other long-term liabilities	285.2	314.3
Total Deferred Credits and Other Liabilities	4,222.4	3,889.6
Commitments and Contingencies (Note P)		
Total Capitalization and Liabilities	$ 14,285.0	$ 13,862.1

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

WISCONSIN ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year Ended December 31

	2012	2011	2010
	(Millions of Dollars)		
Operating Activities			
Net income	$ 546.3	$ 526.2	$ 456.5
Reconciliation to cash			
Depreciation and amortization	371.7	336.4	317.4
Amortization of gain	—	—	(198.4)
Deferred income taxes and investment tax credits, net	352.2	430.6	104.9
Deferred revenue	—	3.5	100.8
Contributions to qualified benefit plans	(100.0)	(277.4)	—
Change in - Accounts receivable and accrued revenues	38.3	30.1	(50.4)
Inventories	21.3	(2.9)	(1.0)
Other current assets	12.1	(20.5)	14.1
Accounts payable	43.8	11.8	21.3
Accrued income taxes, net	57.9	(87.4)	(42.7)
Deferred costs, net	9.2	25.9	25.9
Other current liabilities	(14.9)	44.1	22.0
Other, net	(164.0)	(27.0)	40.0
Cash Provided by Operating Activities	1,173.9	993.4	810.4
Investing Activities			
Capital expenditures	(707.0)	(830.8)	(798.2)
Investment in transmission affiliate	(15.7)	(6.6)	(5.2)
Proceeds from asset sales	8.7	41.5	68.7
Change in restricted cash	42.8	(37.2)	186.2
Other, net	(58.4)	(59.4)	(85.0)
Cash Used in Investing Activities	(729.6)	(892.5)	(633.5)
Financing Activities			
Exercise of stock options	49.8	54.4	90.9
Purchase of common stock	(153.2)	(193.9)	(156.6)
Dividends paid on common stock	(276.3)	(242.0)	(187.0)
Issuance of long-term debt	251.8	720.0	530.0
Retirement and repurchase of long-term debt	(20.3)	(466.6)	(291.7)
Change in short-term debt	(275.3)	12.0	(167.2)
Other, net	0.7	4.8	9.0
Cash Used in Financing Activities	(422.8)	(111.3)	(172.6)
Change in Cash and Cash Equivalents	21.5	(10.4)	4.3
Cash and Cash Equivalents at Beginning of Year	14.1	24.5	20.2
Cash and Cash Equivalents at End of Year	$ 35.6	$ 14.1	$ 24.5

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

WISCONSIN ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF COMMON EQUITY

	Common Stock	Other Paid In Capital	Retained Earnings	Total
	(Millions of Dollars)			
Balance - December 31, 2009	$ 2.3	$ 755.8	$ 2,808.8	$ 3,566.9
Net income			456.5	456.5
Common stock cash dividends of $0.80 per share			(187.0)	(187.0)
Exercise of stock options		90.9		90.9
Purchase of common stock		(156.6)		(156.6)
Tax benefit from share based compensation		21.9		21.9
Stock-based compensation and other		9.5		9.5
Balance - December 31, 2010	2.3	721.5	3,078.3	3,802.1
Net income			526.2	526.2
Common stock cash dividends of $1.04 per share			(242.0)	(242.0)
Exercise of stock options		54.4		54.4
Purchase of common stock		(193.9)		(193.9)
Tax benefit from share based compensation		11.9		11.9
Stock-based compensation and other		4.6		4.6
Balance - December 31, 2011	2.3	598.5	3,362.5	3,963.3
Net income			546.3	546.3
Common stock cash dividends of $1.20 per share			(276.3)	(276.3)
Exercise of stock options		49.8		49.8
Purchase of common stock		(153.2)		(153.2)
Stock-based compensation and other		5.2		5.2
Balance - December 31, 2012	$ 2.3	$ 500.3	$ 3,632.5	$ 4,135.1

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

WISCONSIN ENERGY CORPORATION
CONSOLIDATED STATEMENTS OF CAPITALIZATION

December 31

		2012	2011
		(Millions of Dollars)	
Common Equity (see accompanying statement)		$ 4,135.1	$ 3,963.3
Preferred Stock			
Wisconsin Energy			
$.01 par value; authorized 15,000,000 shares; none outstanding		—	—
Wisconsin Electric			
Six Per Cent. Preferred Stock - $100 par value;			
authorized 45,000 shares; outstanding - 44,498 shares		4.4	4.4
Serial preferred stock -			
$100 par value; authorized 2,286,500 shares; 3.60% Series			
redeemable at $101 per share; outstanding - 260,000 shares		26.0	26.0
$25 par value; authorized 5,000,000 shares; none outstanding		—	—
Total Preferred Stock		30.4	30.4
Long-Term Debt			
Debentures (unsecured)	4.50% due 2013	300.0	300.0
	6.60% due 2013	45.0	45.0
	6.00% due 2014	300.0	300.0
	5.20% due 2015	125.0	125.0
	6.25% due 2015	250.0	250.0
	4.25% due 2019	250.0	250.0
	2.95% due 2021	300.0	300.0
	6-1/2% due 2028	150.0	150.0
	5.625% due 2033	335.0	335.0
	5.90% due 2035	90.0	90.0
	5.70% due 2036	300.0	300.0
	3.65% due 2042	250.0	—
	6-7/8% due 2095	100.0	100.0
Notes (secured, nonrecourse)	4.81% effective rate due 2030	2.0	2.0
	4.91% due 2012-2030	126.7	131.2
	5.209% due 2012-2030	238.6	245.4
	4.673% due 2012-2031	196.7	202.3
	6.00% due 2012-2033	142.1	145.5
	6.09% due 2030-2040	275.0	275.0
	5.848% due 2031-2041	215.0	215.0
	6.00% due 2021	1.8	—
Notes (unsecured)	6.51% due 2013	30.0	30.0
	6.94% due 2028	50.0	50.0
	0.504% variable rate due 2016 (a)	67.0	67.0
	0.504% variable rate due 2030 (a)	80.0	80.0
	Variable rate notes held by Wisconsin Electric	(147.0)	(147.0)
	6.20% due 2033	200.0	200.0
Junior Notes (unsecured)	6.25% due 2067	500.0	500.0
Obligations under capital leases		120.0	132.4
Unamortized discount, net and other		(27.0)	(26.9)
Long-term debt due currently		(412.1)	(32.6)
Total Long-Term Debt		4,453.8	4,614.3
Total Capitalization		$ 8,619.3	$ 8,608.0

(a) Variable interest rate as of December 31, 2012.

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

A -- SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General: Our consolidated financial statements include the accounts of Wisconsin Energy Corporation (Wisconsin Energy, the Company, our, we or us), a diversified holding company, as well as our subsidiaries in the following reportable segments:

- ***Utility Energy Segment*** -- Consisting of Wisconsin Electric and Wisconsin Gas, engaged primarily in the generation of electricity and the distribution of electricity and natural gas; and

- ***Non-Utility Energy Segment*** -- Consisting primarily of We Power, engaged principally in the design, development, construction and ownership of electric power generating facilities for long-term lease to Wisconsin Electric.

Our Corporate and Other segment includes Wispark, which develops and invests in real estate. We have also eliminated all intercompany transactions from the consolidated financial statements.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of certain assets and liabilities and disclosure of contingent assets and liabilities at the date of financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Reclassifications: Certain prior period amounts have been reclassified on a basis consistent with the current period financial statement presentation.

Revenues: We recognize energy revenues on the accrual basis and include estimated amounts for services rendered but not billed.

Our retail electric rates in Wisconsin are established by the PSCW and include base amounts for fuel and purchased power costs. Beginning in January 2011, the electric fuel rules in Wisconsin allow us to defer, for subsequent rate recovery or refund, any under-collection or over-collection of fuel costs that are outside of the symmetrical fuel cost tolerance, which the PSCW set at plus or minus 2% of the approved fuel cost plan. The deferred under-collected amounts are subject to an excess revenues test.

Our retail gas rates include monthly adjustments which permit the recovery or refund of actual purchased gas costs. We defer any difference between actual gas costs incurred (adjusted for a sharing mechanism) and costs recovered through rates as a current asset or liability. The deferred balance is returned to or recovered from customers at intervals throughout the year.

For our We Power assets, we recognize revenues (consisting of the lease payments included in rates and the amortization of the deferred revenue) on a levelized basis over the term of the lease. We depreciate the PTF assets over their estimated useful life.

Accounting for MISO Energy Transactions: The MISO Energy Markets operate under both day-ahead and real-time markets. We record energy transactions in the MISO Energy Markets on a net basis for each hour.

Other Income and Deductions, Net: We recorded the following items in Other Income and Deductions, net for the years ended December 31:

Other Income and Deductions, net	2012	2011	2010
	(Millions of Dollars)		
AFUDC - Equity	$ 35.3	$ 59.4	$ 32.5
Gain on Property Sales	2.7	2.4	4.4
Other, net	(3.2)	0.9	3.3
Total Other Income and Deductions, net	$ 34.8	$ 62.7	$ 40.2

Property and Depreciation: We record property, plant and equipment at cost. Cost includes material, labor, overheads and capitalized interest. Utility property also includes AFUDC - Equity. Additions to and significant replacements of property are charged to property, plant and equipment at cost; minor items are charged to maintenance expense. The cost of depreciable utility property less salvage value is charged to accumulated depreciation when property is retired.

We recorded the following property in service by segment as of December 31:

Property In Service	2012	2011
	(Millions of Dollars)	
Utility Energy	$ 11,080.9	$ 9,817.7
Non-Utility Energy	3,068.5	3,067.5
Other	89.4	92.5
Total	$ 14,238.8	$ 12,977.7

Our utility depreciation rates are certified by the PSCW and MPSC and include estimates for salvage value and removal costs. Depreciation as a percent of average depreciable utility plant was 2.9% in 2012 and 2.8% in 2011 and 2010.

Our We Power assets are being depreciated over the estimated useful life of the various property components. The components have useful lives of between 10 to 45 years for PWGS 1 and PWGS 2, and 10 to 55 years for OC 1 and OC 2.

Our regulated utilities collect in their rates amounts representing future removal costs for many assets that do not have an associated Asset Retirement Obligation (ARO). We record a regulatory liability on our balance sheet for the estimated amounts we have collected in rates for future removal costs less amounts we have spent in removal activities. This regulatory liability was $725.0 million as of December 31, 2012 and $728.2 million as of December 31, 2011.

We recorded the following Construction Work in Progress (CWIP) by segment as of December 31:

CWIP	2012	2011
	(Millions of Dollars)	
Utility Energy	$ 298.2	$ 910.3
Non-Utility Energy	13.3	8.9
Other	4.4	2.1
Total	$ 315.9	$ 921.3

Allowance For Funds Used During Construction - Regulated: AFUDC is included in utility plant accounts and represents the cost of borrowed funds (AFUDC - Debt) used during plant construction, and a return on stockholders' capital (AFUDC - Equity) used for construction purposes. AFUDC - Debt is recorded as a reduction of interest expense, and AFUDC - Equity is recorded in Other Income and Deductions, net.

Our regulated segment recorded the following AFUDC for the years ended December 31:

	2012	2011	2010
		(Millions of Dollars)	
AFUDC - Debt	$ 14.7	$ 24.7	$ 13.5
AFUDC - Equity	$ 35.3	$ 59.4	$ 32.5

Capitalized Interest and Carrying Costs - Non-Regulated Energy: As part of the construction of the PTF electric generating units, we capitalized interest during construction. As allowed under the lease agreements, we were able to collect the carrying costs during the construction of the PTF generating units from our utility customers. The carrying costs that we collected during construction have been recorded as deferred revenue on our balance sheet and we are amortizing the deferred carrying costs to revenue over the individual lease terms.

Earnings per Common Share: We compute basic earnings per common share by dividing our net income attributed to common shareholders by the weighted-average number of common shares outstanding during the period. Diluted earnings per common share is computed by dividing net income attributed to common shareholders by the weighted average number of common shares outstanding during the period, adjusted for the exercise and/or conversion of all potentially dilutive securities. Such dilutive securities include in-the-money stock options. All stock options outstanding during 2012 and 2011 were included in the computation of diluted earnings per share. For 2010, the calculation of diluted earnings per share excluded an immaterial number of out-of-the money stock options that had an anti-dilutive effect. Anti-dilutive shares are excluded from the calculation.

Materials, Supplies and Inventories: Our inventory as of December 31 consists of:

Materials, Supplies and Inventories	2012	2011
	(Millions of Dollars)	
Fossil Fuel	$ 165.5	$ 169.2
Materials and Supplies	121.9	114.1
Natural Gas in Storage	73.3	98.7
Total	$ 360.7	$ 382.0

Substantially all fossil fuel, materials and supplies, and natural gas in storage inventories are recorded using the weighted-average cost method of accounting.

Regulatory Accounting: The economic effects of regulation can result in regulated companies recording costs that have been or are expected to be allowed in the rate-making process in a period different from the period in which the costs would be charged to expense by an unregulated enterprise. When this occurs, costs are deferred as regulatory assets on the balance sheet and expensed in the periods when they are reflected in rates. We defer regulatory assets pursuant to specific or generic orders issued by our regulators. Additionally, regulators can impose regulatory liabilities upon a regulated company for amounts previously collected from customers and for amounts that are expected to be refunded to customers. In general, regulatory assets are recovered in a period between one to eight years. Regulatory assets associated with pension and OPEB expenses are amortized as a component of pension and OPEB expense. Regulatory assets and liabilities that are expected to be amortized within one year are recorded as current on the balance sheet. For further information, see Note C.

Asset Retirement Obligations: We record a liability for a legal ARO in the period in which it is incurred. When a new legal obligation is recorded, we capitalize the costs of the liability by increasing the carrying amount of the related long-lived asset. We accrete the liability to its present value each period and depreciate the capitalized cost over the useful life of the related asset. At the end of the asset's useful life, we settle the obligation for its recorded amount or incur a gain or loss. As it relates to our regulated operations, we apply regulatory accounting guidance and recognize regulatory assets or liabilities for the timing differences between when we recover legal AROs in rates and when we would recognize these costs. For further information, see Note E.

Derivative Financial Instruments: We have derivative physical and financial instruments which we report at fair value. For further information, see Note K.

Cash and Cash Equivalents: Cash and cash equivalents include marketable debt securities acquired three months or less from maturity.

Restricted Cash: As of December 31, 2012 and 2011, restricted cash consists of the settlement we received from the DOE during the first quarter of 2011, which is being returned, net of costs incurred, to customers. As of December 31, 2012, all restricted cash is classified as current.

Margin Accounts: Cash deposited in brokerage accounts for margin requirements is recorded in Other Current Assets on our Consolidated Balance Sheets.

Goodwill: Goodwill reflects the cost of an acquisition in excess of the fair values assigned to identifiable net assets acquired. As of December 31, 2012 and 2011, we had $441.9 million of goodwill recorded at the utility energy segment, which related to our acquisition of Wisconsin Gas in 2000.

Goodwill is not subject to amortization. However, it is subject to fair value-based rules for measuring impairment, and resulting write-downs, if any, are to be reflected in operating expense. Fair value is assessed by considering future discounted cash flows, a comparison of fair value based on public company trading multiples, and merger and acquisition transaction multiples for similar companies. This evaluation utilizes the information available under the circumstances, including reasonable and supportable assumptions and projections. We perform our annual impairment test as of August 31. There was no impairment to the recorded goodwill balance as of our annual 2012 impairment test date.

Impairment or Disposal of Long Lived Assets: We carry property, equipment and goodwill related to businesses held for sale at the lower of cost or estimated fair value less cost to sell. As of December 31, 2012, we had no assets classified as Held for Sale. Long-lived assets are tested for recoverability whenever events or changes in circumstances indicate that their carrying value may not be recoverable from the use and eventual disposition of the asset based on the remaining useful life. An impairment loss is recognized when the carrying amount of an asset is not recoverable and exceeds the fair value of the asset. The carrying amount of an asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. An impairment loss is measured as the excess of the carrying amount of the asset in comparison to the fair value of the asset.

Investments: We account for investments in other affiliated companies in which we do not maintain control using the equity method of accounting. We had a total ownership interest of approximately 26.2% in ATC as of December 31, 2012 and 2011. We are represented by one out of ten ATC board members, each of whom has one vote. Due to the voting requirements, no individual member has more than 10% of the voting control. For further information regarding such investments, see Note O.

Income Taxes: We follow the liability method in accounting for income taxes. Accounting guidance for income taxes requires the recording of deferred assets and liabilities to recognize the expected future tax consequences of events that have been reflected in our financial statements or tax returns and the adjustment of deferred tax balances to reflect tax rate changes. We are required to assess the likelihood that our deferred tax assets would expire before being realized. If we conclude that certain deferred tax assets are likely to expire before being realized, a valuation allowance would be established against those assets. GAAP requires that, if we conclude in a future period that it is more likely than not that some or all of the deferred tax assets would be realized before expiration, we reverse the related valuation allowance in that period. Any change to the allowance, as a result of a change in judgment about the realization of deferred tax assets, is reported in income tax expense.

Investment tax credits associated with regulated operations are deferred and amortized over the life of the assets. We file a consolidated Federal income tax return. Accordingly, we allocate Federal current tax expense benefits and credits to our subsidiaries based on their separate tax computations. For further information, see Note G.

We recognize interest and penalties accrued related to unrecognized tax benefits in Income Taxes in our Consolidated Income Statements, as well as Regulatory Assets or Regulatory Liabilities in our Consolidated Balance Sheets.

We collect sales and use taxes from our customers and remit these taxes to governmental authorities. These taxes are recorded in our Consolidated Income Statements on a net basis.

Stock Options: We estimate the fair value of stock options using the binomial pricing model. We report unearned stock-based compensation associated with non-vested restricted stock and performance share awards activity within Other Paid in Capital in our Consolidated Statements of Common Equity. We report excess tax benefits as a financing cash inflow. Historically, all stock options have been granted with an exercise price equal to the fair market value of the common stock on the date of grant and expire no later than 10 years from grant date. For a discussion of the impacts to our Consolidated Financial Statements, see Note H.

The fair value of our stock options was calculated using a binomial option-pricing model using the following weighted-average assumptions:

	2012	2011	2010
Risk-free interest rate	0.1% - 2.0%	0.2% - 3.4%	0.2% - 3.9%
Dividend yield	3.9%	3.9%	3.7%
Expected volatility	19.0%	19.0%	20.3%
Expected life (years)	5.9	5.5	5.9
Expected forfeiture rate	2.0%	2.0%	2.0%
Weighted-average fair value of our stock options granted	$3.34	$3.17	$3.36

B -- RECENT ACCOUNTING PRONOUNCEMENTS

Offsetting Assets and Liabilities: In December 2011, The Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2011-11, Disclosures about Offsetting Assets and Liabilities. The guidance requires enhanced disclosures about derivatives. Both gross and net information related to eligible transactions will be required under the guidance. This guidance is effective for fiscal years and interim periods beginning on or after January 1, 2013 and must be applied retrospectively. Adoption of this guidance may result in additional disclosures related to derivatives beginning in the first quarter of 2013.

C -- REGULATORY ASSETS AND LIABILITIES

Our primary regulator, the PSCW, considers our regulatory assets and liabilities in two categories, escrowed and deferred. In escrow accounting we expense amounts that are included in rates. If actual costs exceed or are less than the amounts that are allowed in rates, the difference in cost is escrowed on the balance sheet as a regulatory asset or regulatory liability and the escrowed balance is considered in setting future rates. Under deferred cost accounting, we defer amounts to our balance sheet based upon orders or correspondence with our regulators. These deferred costs will be considered in future rate setting proceedings. As of December 31, 2012 and 2011, we had approximately $6.6 million and $11.0 million, respectively, of net regulatory assets that were not earning a return.

In December 2012, the PSCW issued a rate order effective January 1, 2013 that, among other things, reaffirmed our accounting for the regulatory assets and liabilities identified below.

Our regulatory assets and liabilities as of December 31 consist of:

	2012	2011
	(Millions of Dollars)	
Regulatory Assets		
Deferred unrecognized pension costs	$ 731.5	$ 647.8
Deferred income tax related	176.5	121.2
Escrowed electric transmission costs	114.1	118.3
Escrowed conservation	73.5	31.5
Deferred unrecognized OPEB costs	61.6	102.9
Deferred plant related -- capital lease	66.6	73.2
Deferred environmental costs	47.4	48.5
Other, net	109.1	122.3
Total regulatory assets	$ 1,380.3	$ 1,265.7
Regulatory Liabilities		
Deferred cost of removal obligations	$ 725.0	$ 728.2
Escrowed bad debt costs	81.1	69.0
Other, net	62.2	118.7
Total regulatory liabilities	$ 868.3	$ 915.9

Regulatory assets and liabilities that are expected to be amortized within one year are recorded as current on the balance sheet.

D -- ASSET SALES, DIVESTITURES AND DISCONTINUED OPERATIONS

Edison Sault: Effective May 4, 2010, we sold Edison Sault Electric Company (Edison Sault) to Cloverland Electric Cooperative for approximately $63.0 million. We reclassified the operations related to Edison Sault as discontinued operations in the accompanying Consolidated Income Statements. Discontinued Edison Sault operations had no significant impact on our Consolidated Statements of Cash Flows for the year ended December 31, 2010. We retained Edison Sault's ownership interest in ATC.

The following table summarizes the net impacts of the discontinued operations on our earnings for the years ended December 31:

	2012	2011	2010
		(Millions of Dollars)	
Income from Continuing Operations	$ 546.3	$ 512.8	$ 454.4
Income from Discontinued Edison Sault operations, net of tax	—	—	0.7
Income from Discontinued other operations, net of tax (a)	—	13.4	1.4
Net Income	$ 546.3	$ 526.2	$ 456.5

(a) Primarily relates to the 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.

E -- ASSET RETIREMENT OBLIGATIONS

The following table presents the change in our AROs during 2012 and 2011:

	2012	2011
	(Millions of Dollars)	
Balance as of January 1	$ 55.5	$ 52.6
Liabilities Incurred	—	0.6
Liabilities Settled	(14.0)	(2.2)
Accretion	2.8	3.0
Cash Flow Revisions	—	1.5
Balance as of December 31	$ 44.3	$ 55.5

F -- 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 a purchased power agreement which represents a variable interest. This agreement is for 236 MW of firm capacity from a gas-fired cogeneration facility and we account for it 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 $256.3 million of required payments over the remaining term of this agreement. We believe that the required lease payments under this contract will continue to be recoverable in rates. Total capacity and lease payments under contracts considered variable interests in 2012, 2011 and 2010 were $45.8 million, $65.9 million and $64.2 million, respectively. Our maximum exposure to loss is limited to the capacity payments under the contract.

G -- INCOME TAXES

The following table is a summary of income tax expense for each of the years ended December 31:

Income Taxes	2012	2011	2010
		(Millions of Dollars)	
Current tax expense (benefit)	$ (45.9)	$ (166.7)	$ 144.9
Deferred income taxes, net	353.4	434.8	108.6
Investment tax credit, net	(1.2)	(4.2)	(3.6)
Total Income Tax Expense	$ 306.3	$ 263.9	$ 249.9

The provision for income taxes for each of the years ended December 31 differs from the amount of income tax determined by applying the applicable U.S. statutory federal income tax rate to income before income taxes as a result of the following:

Income Tax Expense	2012 Amount	2012 Effective Tax Rate	2011 Amount	2011 Effective Tax Rate	2010 Amount	2010 Effective Tax Rate
	(Millions of Dollars)					
Expected tax at statutory federal tax rates	$ 298.4	35.0%	$ 271.8	35.0%	$ 246.5	35.0%
State income taxes net of federal tax benefit	43.3	5.1%	40.1	5.2%	35.8	5.1%
Production tax credits	(15.9)	(1.9)%	(8.7)	(1.1)%	(7.2)	(1.0)%
Domestic production activities deduction	(12.6)	(1.5)%	(12.6)	(1.6)%	(12.6)	(1.8)%
AFUDC - Equity	(12.3)	(1.4)%	(20.8)	(2.7)%	(11.4)	(1.6)%
Investment tax credit restored	(1.2)	(0.1)%	(4.2)	(0.5)%	(3.6)	(0.5)%
Other, net	6.6	0.7%	(1.7)	(0.3)%	2.4	0.3%
Total Income Tax Expense	$ 306.3	35.9%	$ 263.9	34.0%	$ 249.9	35.5%

The components of deferred income taxes classified as net current assets and net long-term liabilities as of December 31 are as follows:

Deferred Tax Assets	2012	2011
	(Millions of Dollars)	
Current		
Employee benefits and compensation	$ 14.9	$ 14.6
Other	81.1	57.1
Total Current Deferred Tax Assets	96.0	71.7
Non-current		
Future federal tax benefits	334.7	328.5
Deferred revenues	250.0	279.7
Employee benefits and compensation	97.0	103.6
Property-related	28.3	28.3
Construction advances	22.2	25.4
Other	16.3	35.0
Total Non-Current Deferred Tax Assets	748.5	800.5
Total Deferred Tax Assets	$ 844.5	$ 872.2

Deferred Tax Liabilities	2012	2011
	(Millions of Dollars)	
Current		
Prepaid items	$ 49.7	$ 50.1
Total Current Deferred Tax Liabilities	49.7	50.1
Non-current		
Property-related	2,339.4	2,020.7
Employee benefits and compensation	244.3	232.8
Investment in transmission affiliate	144.9	129.2
Deferred transmission costs	45.7	47.4
Other	91.2	66.5
Total Non-current Deferred Tax Liabilities	2,865.5	2,496.6
Total Deferred Tax Liabilities	$ 2,915.2	$ 2,546.7

Consolidated Balance Sheet Presentation	2012	2011
Current Deferred Tax Asset	$ 46.3	$ 21.6
Non-Current Deferred Tax Liability	$ 2,117.0	$ 1,696.1

Consistent with rate-making treatment, deferred taxes are offset in the above table for temporary differences which have related regulatory assets or liabilities.

As of December 31, 2012, we had approximately $838.5 million and $41.2 million of net operating loss and tax credit carryforwards resulting in deferred tax assets of $293.5 million and $41.2 million, respectively. As of December 31, 2011, we had approximately $867.1 million and $25.0 million of net operating loss and tax credit carryforwards resulting in deferred tax assets of $303.5 million and $25.0 million, respectively. The tax credit and net operating loss carryforwards begin to expire in 2029. We anticipate that we will have future taxable income sufficient to utilize these deferred tax assets.

We adopted accounting guidance related to uncertainty in income taxes. A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

	2012	2011
	(Millions of Dollars)	
Balance as of January 1	$ 11.1	$ 29.5
Additions for tax positions of prior years	10.8	—
Reductions for tax positions of prior years	(10.6)	(13.9)
Reductions due to statute of limitations	—	(2.5)
Settlements during the period	—	(2.0)
Balance as of December 31	$ 11.3	$ 11.1

The amount of unrecognized tax benefits as of December 31, 2012 and 2011 excludes deferred tax assets related to uncertainty in income taxes of $10.2 million and $11.0 million, respectively. As of December 31, 2012 and 2011, the net amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate for continuing operations was approximately $1.0 million and $0.1 million, respectively.

We recognize interest and penalties accrued related to unrecognized tax benefits as a component of income tax expense. For the years ended December 31, 2012, 2011 and 2010, we recognized approximately $0.2 million, $0.7 million and $4.1 million, respectively, of accrued interest in the Consolidated Income Statements. For the years ended December 31, 2012 and 2010, we recognized no penalties in the Consolidated Income Statements. For the year ended December 31, 2011, we recognized a benefit of $0.3 million in the Consolidated Income Statements related to a reduction of accrued penalties. We had approximately $0.3 million and $2.0 million of interest accrued and no penalties accrued on the Consolidated Balance Sheets as of December 31, 2012 and 2011, respectively.

Within the next twelve months, it is reasonably possible that our unrecognized tax benefits may decrease by $1.4 million as a result of further IRS guidance relating to an uncertain tax position.

Our primary tax jurisdictions include Federal and the state of Wisconsin. Currently, the tax years of 2007 through 2012 are subject to Federal and Wisconsin examination.

H -- COMMON EQUITY

As of December 31, 2012 and 2011, we had 325,000,000 shares of common stock authorized under our charter, of which 229,039,456 and 230,486,804 common shares, respectively, were outstanding. All share-based compensation is currently fulfilled by purchases on the open market by our independent agents and do not dilute shareholders' ownership.

Share-Based Compensation Plans: We have a plan that was approved by stockholders that enables us to provide a long-term incentive through equity interests in Wisconsin Energy to outside directors, selected officers and key employees of the Company. The plan provides for the granting of stock options, stock appreciation rights, restricted stock awards and performance shares. Awards may be paid in common stock, cash or a combination thereof. 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 the terms of outstanding stock options during the period other than necessary adjustments as a result of our stock split.

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 as of December 31:

	2012	2011	2010
	(Millions of Dollars)		
Performance units	$ 16.3	$ 24.1	$ 26.0
Stock options	2.7	2.6	7.6
Restricted stock	3.0	1.8	1.5
Share-based compensation expense	$ 22.0	$ 28.5	$ 35.1
Related Tax Benefit	$ 8.8	$ 11.4	$ 14.1

Stock Options: The exercise price of a stock option under the plan is to be no less than 100% of the common stock's fair market value on the grant date and options may not be exercised within six months of the grant date except in the event of a change in control. Option grants consist of non-qualified stock options and vest on a cliff-basis after a three year period. Options expire no later than 10 years from the date of grant. For further information regarding stock-based compensation and the valuation of our stock options, see Note A.

We expect that substantially all of the outstanding options as of December 31, 2012 will be exercised.

The following is a summary of our stock option activity during 2012:

Stock Options	Number of Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (Millions)
Outstanding as of January 1, 2012	10,638,750	$ 21.65		
Granted	938,770	$ 34.88		
Exercised	(2,643,931)	$ 18.84		
Forfeited	(13,920)	$ 28.88		
Outstanding as of December 31, 2012	8,919,669	$ 23.86	5.3	$ 115.8
Exercisable as of December 31, 2012	7,217,394	$ 22.19	4.6	$ 105.8

In January 2013, the Compensation Committee of the Board of Directors (Compensation Committee) awarded 1,418,560 non-qualified stock options with an exercise price of $37.46 to our officers and other key employees under its normal schedule of awarding long-term incentive compensation.

The intrinsic value of options exercised during the years ended December 31, 2012, 2011 and 2010 was $47.5 million, $36.1 million and $62.1 million, respectively. Cash received from options exercised during the years ended December 31, 2012, 2011 and 2010 was $49.8 million, $54.4 million and $90.9 million, respectively. The actual tax benefit realized for the tax deductions from option exercises for the same periods was approximately zero, $14.3 million and $24.1 million, respectively.

The following table summarizes information about stock options outstanding as of December 31, 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	1,661,507	$ 18.74	2.5	1,661,507	$ 18.74	2.5
$21.11 to $24.92	5,877,372	$ 23.14	5.2	5,429,372	$ 22.99	5.1
$29.35 to $34.88	1,380,790	$ 33.09	8.7	126,515	$ 32.69	8.6
	8,919,669	$ 23.86	5.3	7,217,394	$ 22.19	4.6

The following table summarizes information about our non-vested options during 2012:

Non-Vested Stock Options	Number of Options	Weighted-Average Fair Value
Non-Vested as of January 1, 2012	3,103,770	$ 3.78
Granted	938,770	$ 3.34
Vested	(2,326,345)	$ 3.96
Forfeited	(13,920)	$ 3.29
Non-Vested as of December 31, 2012	1,702,275	$ 3.31

As of December 31, 2012, total compensation costs related to non-vested stock options not yet recognized was approximately $1.0 million, which is expected to be recognized over the next 21 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 2012:

Restricted Shares	Number of Shares	Weighted-Average Market Price
Outstanding as of January 1, 2012	192,558	
Granted	94,959	$ 34.46
Released	(93,250)	$ 29.87
Forfeited	(6,045)	$ 31.00
Outstanding as of December 31, 2012	188,222	

Recipients of previously issued restricted shares have the right to vote the shares and receive dividends, and the shares have vesting periods ranging up to 10 years.

In January 2013, the Compensation Committee awarded 74,290 restricted shares to our directors, officers and other key employees under its normal schedule of awarding long-term incentive compensation. 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 also have voting rights and are entitled to dividends in the same manner as other shareholders.

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 $3.5 million, $2.5 million and $2.3 million for the years ended December 31, 2012, 2011, and 2010, respectively. The actual tax benefit realized for the tax deductions from released restricted shares for the same years was zero, $0.8 million and $0.7 million, respectively.

As of December 31, 2012, total compensation cost related to restricted stock not yet recognized was approximately $2.6 million, which is expected to be recognized over the next 21 months on a weighted-average basis.

Performance Units: In January 2012, 2011 and 2010, the Compensation Committee awarded 346,570, 435,690 and 555,830 performance units, respectively, to officers and other key employees under the Wisconsin Energy Performance Unit Plan. Under the grants, the ultimate number of units that will be awarded is dependent upon the achievement of certain financial performance of our stock over a three-year period. Under the terms of the award, participants may earn between 0% and 175% of the base performance unit award. All grants are settled in cash. We are accruing compensation costs over the three-year performance period based on our estimate of the final expected value of the awards. Performance units earned as of December 31, 2012, 2011 and 2010 vested and were settled during the first quarter of 2013, 2012 and 2011 and had a total intrinsic value of $19.3 million, $26.7 million and $12.6 million, respectively. The actual tax benefit realized for the tax deductions from the distribution of performance units was approximately $7.0 million, $9.7 million and $4.3 million, respectively.

In January 2013, the Compensation Committee awarded 239,120 performance units to our officers and other key employees under its normal schedule of awarding long-term incentive compensation.

As of December 31, 2012, total compensation cost related to performance units not yet recognized was approximately $13.7 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 Wisconsin Energy 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.

Wisconsin Electric and Wisconsin Gas are required to maintain capital structures that differ from GAAP as they reflect regulatory adjustments. Consistent with the 2010 rate case order, the 2013 PSCW rate case order requires Wisconsin Electric to maintain a common equity ratio range of between 48.5% and 53.5%, and Wisconsin Gas to maintain a capital structure which has a common equity range of between 45.0% and 50.0%. Each company is in compliance with its respective common equity range. Wisconsin Electric and Wisconsin Gas must obtain PSCW approval if they pay dividends above the test year levels that would cause either company to fall below the authorized levels of common equity.

Wisconsin Electric may not pay common dividends to Wisconsin Energy under Wisconsin Electric's Restated Articles of Incorporation if any dividends on Wisconsin Electric's outstanding preferred stock have not been paid. In addition, pursuant to the terms of Wisconsin Electric's 3.60% Serial Preferred Stock, Wisconsin Electric's ability to declare common dividends would be limited to 75% or 50% of net income during a twelve month period if Wisconsin Electric's common stock equity to total capitalization, as defined in the preferred stock designation, is less than 25% and 20%, respectively.

We have the option to defer interest payments on the Junior Notes, from time to time, for one or more periods of up to 10 consecutive years per period. During any period in which we defer interest payments, we may not declare or pay any dividends or distributions on, or redeem, repurchase or acquire, our common stock.

As of December 31, 2012, the restricted net assets of consolidated and unconsolidated subsidiaries and our equity in undistributed earnings of 50% or less owned investees accounted for by the equity method total approximately $3.6 billion. This amount exceeds 25% of our consolidated net assets as of December 31, 2012.

See Note J for discussion of certain financial covenants related to the bank back-up credit facilities of Wisconsin Energy, Wisconsin Electric and Wisconsin Gas.

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

Share Repurchase Program: We do not expect to issue new shares under our various employee benefit plans and our dividend reinvestment and share purchase plan; rather, we instruct independent plan agents to purchase the shares in the open market. In that regard, no new shares of common stock were issued in 2012, 2011 or 2010.

In May 2011, our Board of Directors authorized a share repurchase program for up to $300 million of our common stock through the end of 2013. The repurchase program does not obligate Wisconsin Energy to acquire any specific number of shares and may be suspended or terminated by the Board of Directors at any time. Through December 31, 2012, we repurchased approximately 4.7 million shares pursuant to this program at an average cost of $32.63 per share and a total cost of $151.8 million. 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 for the year ending December 31:

	2012		2011		2010	
	Shares	Cost	Shares	Cost	Shares	Cost
	(In Millions)					
Under May 2011 share repurchase program	1.5	$ 51.8	3.2	$ 100.0	—	$ —
To fulfill exercised stock options and restricted stock awards	2.8	101.4	3.0	93.9	5.8	156.6
Total	4.3	$ 153.2	6.2	$ 193.9	5.8	$ 156.6

I -- LONG-TERM DEBT AND CAPITAL LEASE OBLIGATIONS

Debentures and Notes: As of December 31, 2012, the maturities and sinking fund requirements of our long-term debt outstanding (excluding obligations under capital leases) were as follows:

	(Millions of Dollars)
2013	$ 396.3
2014	322.4
2015	399.5
2016	27.4
2017	29.5
Thereafter	3,597.8
Total	$ 4,772.9

We amortize debt premiums, discounts and debt issuance costs over the lives of the debt and we include the costs in interest expense.

In December 2012, Wisconsin Electric issued $250 million of 3.65% Debentures due December 15, 2042. 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 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.

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

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

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

During 2010, we retired $281.5 million of unsecured notes through the issuance of long-term and short-term debt.

Wisconsin Electric is the obligor under two series of tax-exempt pollution control refunding bonds in outstanding principal amount of $147 million. In August 2009, Wisconsin Electric terminated letters of credit that provided credit and liquidity support for the bonds, which resulted in a mandatory tender of the bonds. Wisconsin Electric purchased the bonds at par plus accrued interest to the date of purchase. As of December 31, 2012 and 2011, the repurchased bonds were still outstanding, but were reported as a reduction in our consolidated long-term debt because they are held by Wisconsin Electric. Depending on market conditions and other factors, Wisconsin Electric may change the method used to determine the interest rate on the bonds and have them remarketed to third parties.

In connection with our outstanding Junior Notes, we executed the Replacement Capital Covenant dated May 11, 2007 (RCC) for the benefit of persons that buy, hold or sell a specified series of long-term indebtedness (covered debt). Our 6.20% Senior Notes due April 1, 2033 have been designated as the covered debt under the RCC. The RCC provides that we may not redeem, defease or purchase and our subsidiaries may not purchase any Junior Notes on or before May 15, 2037, unless, subject to certain limitations described in the RCC, during the 180 days prior to the date of redemption, defeasance or purchase, we have received a specified amount of proceeds from the sale of qualifying securities.

Obligations Under Capital Leases: In 1997, Wisconsin Electric entered into a 25-year power purchase contract with an unaffiliated independent power producer. The contract, for 236 MW of firm capacity from a gas-fired cogeneration facility, includes no minimum energy requirements. When the contract expires in 2022, Wisconsin Electric may, at its option and with proper notice, renew for another ten years or purchase the generating facility at fair value or allow the contract to expire. We account for this contract as a capital lease and recorded the leased facility and corresponding obligation under the capital lease at the estimated fair value of the plant's electric generating facilities. We are amortizing the leased facility on a straight-line basis over the original 25-year term of the contract.

We treat the long-term power purchase contract as an operating lease for rate-making purposes and we record our minimum lease payments as purchased power expense on the Consolidated Income Statements. We paid a total of $32.5 million and $31.3 million in lease payments during 2012 and 2011, respectively. We record the difference between the minimum lease payments and the sum of imputed interest and amortization costs calculated under capital lease accounting as a deferred regulatory asset on our Consolidated Balance Sheets (see Regulatory Assets - Deferred plant related -- capital lease in Note C). Due to the timing and the amounts of the minimum lease payments, the regulatory asset increased to approximately $78.5 million during 2009, at which time the regulatory asset began to be reduced to zero over the remaining life of the contract. The total obligation under the capital lease was $120.0 million as of December 31, 2012, and will decrease to zero over the remaining life of the contract.

The following is a summary of our capitalized leased facilities as of December 31:

Capital Lease Assets	2012	2011
	(Millions of Dollars)	
Leased Facilities		
Long-term power purchase commitment	$ 140.3	$ 140.3
Accumulated amortization	(86.8)	(81.1)
Total Leased Facilities	$ 53.5	$ 59.2

Future minimum lease payments under our capital lease and the present value of our net minimum lease payments as of December 31, 2012 are as follows:

	(Millions of Dollars)
2013	$ 40.4
2014	41.9
2015	43.5
2016	45.1
2017	13.9
Thereafter	71.5
Total Minimum Lease Payments	256.3
Less: Estimated Executory Costs	(68.4)
Net Minimum Lease Payments	187.9
Less: Interest	(67.9)
Present Value of Net Minimum Lease Payments	120.0
Less: Due Currently	(15.8)
	$ 104.2

J -- SHORT-TERM DEBT

Short-term notes payable balances and their corresponding weighted-average interest rates as of December 31 consist of:

Short-Term Debt	2012 Balance	2012 Interest Rate	2011 Balance	2011 Interest Rate
	(Millions of Dollars, except for percentages)			
Commercial paper	$ 394.6	0.30%	$ 669.9	0.27%

The following information relates to commercial paper for the years ended December 31:

	2012	2011
	(Millions of Dollars, except for percentages)	
Maximum Short-Term Debt Outstanding	$ 669.9	$ 717.3
Average Short-Term Debt Outstanding	$ 481.6	$ 505.1
Weighted-Average Interest Rate	0.28%	0.25%

In December 2012, Wisconsin Energy, Wisconsin Electric and Wisconsin Gas entered into new bank back-up credit facilities to maintain short-term credit liquidity which, among other terms, require the companies to maintain, subject to certain exclusions, a minimum total funded debt to capitalization ratio of less than 70%, 65% and 65%, respectively.

As of December 31, 2012, we had approximately $1.2 billion of available undrawn lines under our bank back-up credit facilities and approximately $394.6 million of commercial paper outstanding that was supported by the available lines of credit. Our bank back-up credit facilities expire in December 2017.

The Wisconsin Energy, Wisconsin Electric and Wisconsin Gas bank back-up credit facilities contain customary covenants, including certain limitations on the respective companies' ability to sell assets. The credit facilities also contain customary events of default, including payment defaults, material inaccuracy of representations and warranties, covenant defaults, bankruptcy proceedings, certain judgments, ERISA defaults and change of control. In addition, pursuant to the terms of Wisconsin Energy's credit agreement, Wisconsin Energy must ensure that certain of its subsidiaries comply with several of the covenants contained therein.

As of December 31, 2012, we were in compliance with all financial covenants.

K -- DERIVATIVE INSTRUMENTS

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

We record derivative instruments on the balance sheet as an asset or liability measured at its fair value, and changes in the derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are met or we receive regulatory treatment for the derivative. For most energy related physical and financial contracts in our regulated operations that qualify as derivatives, the PSCW allows the effects of the fair market value accounting to be offset to regulatory assets and liabilities. We do not offset fair value amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral against fair value amounts recognized for derivatives executed with the same counterparty under the same master netting arrangement. As of December 31, 2012, we recognized $7.6 million in regulatory assets and $17.5 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 other current assets and the current portion of the liabilities in other current liabilities. The long-term portion of our derivative assets of $0.6 million is recorded in other deferred charges and other assets, and we had no long-term portion of derivative liabilities. Our Consolidated Balance Sheets as of December 31, 2012 and 2011 include:

	December 31, 2012		December 31, 2011	
	Derivative Asset	Derivative Liability	Derivative Asset	Derivative Liability
	(Millions of Dollars)			
Natural Gas	$ 1.7	$ 0.5	$ 2.1	$ 9.1
Fuel Oil	0.4	—	0.3	0.1
FTRs	4.7	—	5.7	—
Coal	11.1	—	12.5	—
Total	$ 17.9	$ 0.5	$ 20.6	$ 9.2

Our Consolidated Income Statements include gains (losses) on derivative instruments used in our risk management strategies under fuel and purchased power for those commodities supporting our electric operations and under cost of gas sold for the natural gas sold to our customers. Our estimated notional volumes and gains (losses) for the years ended December 31 were as follows:

	2012		2011	
	Volume	Gains (Losses)	Volume	Gains (Losses)
		(Millions of Dollars)		(Millions of Dollars)
Natural Gas	77.2 million Dth	$ (36.3)	71.8 million Dth	$ (33.4)
Fuel Oil	7.0 million gallons	1.8	13.0 million gallons	6.9
FTRs	20,616 MW	6.1	23,718 MW	12.5
Total		$ (28.4)		$ (14.0)

As of December 31, 2012 and 2011, we posted collateral of $2.9 million and $11.9 million, respectively, in our margin accounts. These amounts are recorded on the balance sheets in other current assets.

L -- FAIR VALUE MEASUREMENTS

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

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

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

Level 1 -- 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 December 31, 2012			
	Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Assets:				
Restricted Cash	$ 2.7	$ —	$ —	$ 2.7
Derivatives	0.9	12.3	4.7	17.9
Total	$ 3.6	$ 12.3	$ 4.7	$ 20.6
Liabilities:				
Derivatives	$ 0.5	$ —	$ —	$ 0.5
Total	$ 0.5	$ —	$ —	$ 0.5

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 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:

	2012	2011
	(Millions of Dollars)	
Balance as of January 1	$ 5.7	$ 5.9
Realized and unrealized gains (losses)	—	—
Purchases	11.0	16.1
Issuances	—	—
Settlements	(12.0)	(16.3)
Transfers in and/or out of Level 3	—	—
Balance as of December 31	$ 4.7	$ 5.7
Change in unrealized gains (losses) relating to instruments still held as of December 31	$ —	$ —

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 K -- 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 as of December 31 are as follows:

	2012		2011	
Financial Instruments	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(Millions of Dollars)			
Preferred stock, no redemption required	$ 30.4	$ 26.0	$ 30.4	$ 25.1
Long-term debt including current portion	$ 4,772.9	$ 5,447.3	$ 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.

M -- BENEFITS

Pensions and Other Post-retirement Benefits: We have defined benefit pension plans that cover substantially all of our employees. Generally, employees who started with the company after 1995 receive a benefit based on a percentage of their annual salary plus an interest credit, while employees who started before 1996 receive a benefit based upon years of service and final average salary. Approximately half of our projected benefit obligation relates to benefits based upon years of service and final average salary.

We also have OPEB plans covering substantially all of our employees. The health care plans are contributory with participants' contributions adjusted annually; the life insurance plans are noncontributory. The accounting for the health care plans anticipates future cost-sharing changes to the written plans that are consistent with our expressed intent to maintain the current cost sharing levels. The post-retirement health care plans include a limit on our share of costs for recent and future retirees.

We use a year-end measurement date to measure the funded status of all of our pension and OPEB plans. Due to the regulated nature of our business, we have concluded that substantially all of the unrecognized costs resulting from the recognition of the funded status of our pension and OPEB plans qualify as a regulatory asset.

The following table presents details about our pension and OPEB plans:

	Pension		OPEB	
	2012	2011	2012	2011
	(Millions of Dollars)			
Change in Benefit Obligation				
Benefit Obligation at January 1	$ 1,330.6	$ 1,222.8	$ 389.7	$ 368.3
Service cost	21.7	15.9	10.3	10.4
Interest cost	65.5	67.6	20.3	20.8
Participants' contributions	—	—	9.6	11.6
Plan amendments	—	—	0.5	0.4
Actuarial loss (gain)	166.5	98.0	(23.8)	7.6
Other accrued benefits	31.4	—	—	—
Gross benefits paid	(107.2)	(73.7)	(26.3)	(30.3)
Federal subsidy on benefits paid	N/A	N/A	0.9	0.9
Benefit Obligation at December 31	$ 1,508.5	$ 1,330.6	$ 381.2	$ 389.7
Change in Plan Assets				
Fair Value at January 1	$ 1,262.5	$ 1,059.5	$ 255.4	$ 216.7
Actual earnings on plan assets	127.4	33.8	29.0	9.0
Employer contributions	102.7	242.9	17.7	48.4
Participants' contributions	—	—	9.6	11.6
Gross benefits paid	(107.2)	(73.7)	(26.3)	(30.3)
Fair Value at December 31	$ 1,385.4	$ 1,262.5	$ 285.4	$ 255.4
Net Liability	$ 123.1	$ 68.1	$ 95.8	$ 134.3

As of December 31, 2012, our qualified and non-qualified pension plans were under-funded by $20.9 million and $102.2 million, respectively. As of December 31, 2011, our qualified pension plans were over-funded by $24.4 million and our non-qualified pension plans were underfunded by $92.5 million.

Amounts recognized in our Consolidated Balance Sheets as of December 31 related to the funded status of the benefit plans consisted of:

	Pension		OPEB	
	2012	2011	2012	2011
	(Millions of Dollars)			
Other deferred charges	$ —	$ —	$ 25.1	$ 20.3
Other long-term liabilities	123.1	68.1	120.9	154.6
Net liability	$ 123.1	$ 68.1	$ 95.8	$ 134.3

The accumulated benefit obligation for all defined benefit plans was $1,507.1 million and $1,329.4 million as of December 31, 2012 and 2011, respectively.

The following table shows the amounts that have not yet been recognized in our net periodic benefit cost as of December 31 and are recorded as a regulatory asset on our balance sheet:

	Pension		OPEB	
	2012	2011	2012	2011
	(Millions of Dollars)			
Net actuarial loss	$ 719.2	$ 633.4	$ 65.3	$ 108.1
Prior service costs (credits)	12.2	14.4	(3.7)	(6.1)
Transition obligation	—	—	—	0.3
Total	$ 731.4	$ 647.8	$ 61.6	$ 102.3

We estimate that 2013 periodic pension and OPEB costs will include the amortization of previously unrecognized benefit costs referred to above of $56.0 million and $1.5 million, respectively.

The components of net periodic pension and OPEB costs for the years ended December 31 are as follows:

	Pension			OPEB		
	2012	2011	2010	2012	2011	2010
	(Millions of Dollars)					
Net Periodic Benefit Cost						
Service cost	$ 21.7	$ 15.9	$ 23.7	$ 10.3	$ 10.4	$ 11.2
Interest cost	65.5	67.6	68.4	20.3	20.8	21.2
Expected return on plan assets	(89.6)	(82.1)	(78.2)	(19.0)	(16.9)	(14.3)
Amortization of:						
Transition obligation	—	—	—	0.3	0.3	0.3
Prior service cost (credit)	2.2	2.2	2.2	(1.9)	(1.9)	(11.9)
Actuarial loss	41.0	34.0	26.8	7.3	6.2	10.8
Other	0.4	—	—	—	—	(0.4)
Net Periodic Benefit Cost	$ 41.2	$ 37.6	$ 42.9	$ 17.3	$ 18.9	$ 16.9

In addition to the costs above, in 2011 we recorded net pension costs of less than $0.04 per share related to the settlement of pension litigation. See Note P -- Commitments and Contingencies in this report. The charges were after considering insurance and reserves established in 2010.

	Pension			OPEB		
	2012	2011	2010	2012	2011	2010
Weighted-Average assumptions used to determine benefit obligations as of Dec. 31						
Discount rate	4.10%	5.05%	5.60%	4.15%	5.20%	5.70%
Rate of compensation increase	4.0%	4.0%	4.0%	N/A	N/A	N/A
Weighted-Average assumptions used to determine net cost for year ended Dec. 31						
Discount rate	5.05%	5.60%	6.05%	5.20%	5.70%	5.75%
Expected return on plan assets	7.25%	7.25%	7.25%	7.50%	7.50%	7.50%
Rate of compensation increase	4.0%	4.0%	4.0%	N/A	N/A	N/A

Assumed health care cost trend rates as of Dec. 31	2012	2011	2010
Health care cost trend rate assumed for next year (Pre 65 / Post 65)	7.5%/7.5%	8.0%/12%	7.5%/16%
Rate that the cost trend rate gradually adjusts to	5.0%	5.0%	5.0%
Year that the rate reaches the rate it is assumed to remain at (Pre 65 / Post 65)	2017/2017	2017/2017	2015/2016

The expected long-term rate of return on pension and OPEB plan assets was 7.25% and 7.50%, respectively, in 2012, 2011 and 2010. We consult with our investment advisors on an annual basis to help us forecast expected long-term returns on plan assets by reviewing historical returns as well as calculating expected total trust returns using the weighted-average of long-term market returns for each of the major target asset categories utilized in the fund.

A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	1% Increase	1% Decrease
	(Millions of Dollars)	
Effect on		
Post-retirement benefit obligation	$ 27.8	$ (23.5)
Total of service and interest cost components	$ 4.0	$ (3.2)

We use various Employees' Benefit Trusts to fund a major portion of OPEB. The majority of the trusts' assets are mutual funds.

Plan Assets: Current pension trust assets and amounts which are expected to be contributed to the trusts in the future are expected to be adequate to meet pension payment obligations to current and future retirees.

The Investment Trust Policy Committee oversees investment matters related to all of our funded benefit plans. The Committee works with external actuaries and investment consultants on an on-going basis to establish and monitor investment strategies and target asset allocations. Forecasted cash flows for plan liabilities are regularly updated based on annual valuation results. Target allocations are determined utilizing projected benefit payment cash flows and risk analyses of appropriate investments. They are intended to reduce risk, provide long-term financial stability for the plans and maintain funded levels which meet long-term plan obligations while preserving sufficient liquidity for near-term benefit payments.

Our current pension plan target asset allocation is 45% equity investments and 55% fixed income investments. The current OPEB target asset allocation is 60% equity investments and 40% fixed income investments. Equity securities include investments in large-cap, mid-cap and small-cap companies primarily located in the United States. Fixed income securities include corporate bonds of companies from diversified industries, mortgage and other asset backed securities, commercial paper, and U.S. Treasuries.

The following table summarizes the fair value of our pension plan assets by asset category within the fair value hierarchy (for further level information, see Note L):

	As of December 31, 2012			
Asset Category - Pension	Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Cash and Cash Equivalents	$ 13.7	$ —	$ —	$ 13.7
Equities:				
U.S. Equity	466.3	—	—	466.3
International Equity	134.7	30.4	—	165.1
Fixed Income				
Short, Intermediate and Long-term Bonds (a)				
U.S. Bonds	67.7	546.6	—	614.3
International Bonds	80.7	45.3	—	126.0
Total	$ 763.1	$ 622.3	$ —	$ 1,385.4

	As of December 31, 2011			
Asset Category - Pension	Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Cash and Cash Equivalents	$ 8.5	$ —	$ —	$ 8.5
Equities:				
U.S. Equity	455.1	—	—	455.1
International Equity	100.4	33.9	—	134.3
Fixed Income				
Short, Intermediate and Long-term Bonds (a)				
U.S. Bonds	76.9	502.8	—	579.7
International Bonds	40.9	44.0	—	84.9
Total	$ 681.8	$ 580.7	$ —	$ 1,262.5

(a) This category represents investment grade bonds of U.S. and foreign issuers denominated in U.S. dollars from diverse industries.

The following table summarizes the fair value of our OPEB plan assets by asset category within the fair value hierarchy:

Asset Category - OPEB	As of December 31, 2012 Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Cash and Cash Equivalents	$ 1.7	$ —	$ —	$ 1.7
Equities:				
U.S. Equity	125.9	—	—	125.9
International Equity	39.9	2.2	—	42.1
Fixed Income:				
Short, Intermediate and Long-term Bonds (a)				
U.S. Bonds	5.0	89.9	—	94.9
International Bonds	15.4	5.4	—	20.8
Total	$ 187.9	$ 97.5	$ —	$ 285.4

Asset Category - OPEB	As of December 31, 2011 Level 1	Level 2	Level 3	Total
	(Millions of Dollars)			
Cash and Cash Equivalents	$ 2.4	$ —	$ —	$ 2.4
Equities:				
U.S. Equity	113.6	—	—	113.6
International Equity	32.1	2.3	—	34.4
Fixed Income:				
Short, Intermediate and Long-term Bonds (a)				
U.S. Bonds	8.2	83.0	—	91.2
International Bonds	8.7	5.1	—	13.8
Total	$ 165.0	$ 90.4	—	$ 255.4

(a) This category represents investment grade bonds of U.S. and foreign issuers denominated in U.S. dollars from diverse industries.

Cash Flows:

Employer Contributions	Pension Qualified	Pension Non-Qualified	OPEB
	(Millions of Dollars)		
2010	$ —	$ 6.8	$ 4.9
2011	$ 236.4	$ 6.5	$ 48.4
2012	$ 95.6	$ 7.1	$ 17.7

The following table identifies our expected benefit payments over the next 10 years:

Year	Pension	Gross OPEB
	(Millions of Dollars)	
2013	$ 101.4	$ 23.3
2014	$ 99.5	$ 20.8
2015	$ 98.9	$ 21.0
2016	$ 99.1	$ 21.5
2017	$ 99.8	$ 22.2
2018-2022	$ 489.4	$ 113.9

Savings Plans: We sponsor savings plans which allow employees to contribute a portion of their pre-tax and/or after-tax income in accordance with plan-specified guidelines. Under these plans, we expensed matching contributions of $13.8 million, $14.1 million and $13.8 million during 2012, 2011 and 2010, respectively.

Postemployment Benefits: Postemployment benefits provided to former or inactive employees are recognized when an event occurs. The estimated liability for such benefits was $4.0 million as of December 31, 2012.

N -- SEGMENT REPORTING

Our reportable segments as of December 31, 2012 include a utility energy segment and a non-utility energy segment. We have organized our reportable segments based upon the regulatory environment in which our utility subsidiaries operate and on how management makes decisions and measures performance. The segments are managed separately because each business requires different technology and marketing strategies. The accounting policies of the reportable operating segments are the same as those described in Note A.

Our utility energy segment primarily includes our electric and natural gas utility operations. Our electric utility operation engages in the generation, distribution and sale of electric energy in southeastern (including metropolitan Milwaukee), east central and northern Wisconsin and in the Upper Peninsula of Michigan. Our natural gas utility operation is engaged in the purchase, distribution and sale of natural gas to retail customers and the transportation of customer-owned natural gas throughout Wisconsin. Our non-utility energy segment derives its revenues primarily from the ownership of electric power generating facilities for long-term lease to Wisconsin Electric.

Summarized financial information concerning our reportable segments for each of the three years ended December 31, 2012 is shown in the following table. The segment information below includes income from discontinued operations as a result of the sale of Edison Sault in May 2010.

Year Ended	Reportable Segments Energy Utility	Reportable Segments Energy Non-Utility	Corporate & Other (a)	Eliminations & Reconciling Items	Total Consolidated
	(Millions of Dollars)				
December 31, 2012					
Operating Revenues (b)	$ 4,190.8	$ 439.9	$ 1.2	$ (385.5)	$ 4,246.4
Depreciation and Amortization	$ 296.4	$ 67.1	$ 0.7	$ —	$ 364.2
Operating Income (Loss)	$ 647.7	$ 358.8	$ (6.2)	$ —	$ 1,000.3
Equity in Earnings of Unconsolidated Affiliates	$ 65.7	$ —	$ (0.2)	$ —	$ 65.5
Interest Expense, Net	$ 129.4	$ 66.7	$ 52.5	$ (0.4)	$ 248.2
Income Tax Expense (Benefit)	$ 214.9	$ 116.6	$ (25.2)	$ —	$ 306.3
Income from Discontinued Operations, Net of Tax	$ —	$ —	$ —	$ —	$ —
Net Income (Loss)	$ 400.6	$ 175.9	$ 546.1	$ (576.3)	$ 546.3
Capital Expenditures	$ 697.3	$ 5.5	$ 4.2	$ —	$ 707.0
Total Assets (c)	$ 13,988.1	$ 2,903.5	$ 4,431.4	$ (7,038.0)	$ 14,285.0
December 31, 2011					
Operating Revenues (b)	$ 4,431.5	$ 435.1	$ 0.9	$ (381.1)	$ 4,486.4
Depreciation and Amortization	$ 257.0	$ 72.5	$ 0.7	$ —	$ 330.2
Operating Income (Loss)	$ 544.8	$ 348.9	$ (6.4)	$ —	$ 887.3
Equity in Earnings of Unconsolidated Affiliates	$ 62.5	$ —	$ (0.9)	$ —	$ 61.6
Interest Expense, Net	$ 110.0	$ 66.7	$ 59.5	$ (0.4)	$ 235.8
Income Tax Expense (Benefit)	$ 182.7	$ 112.8	$ (31.6)	$ —	$ 263.9
Income from Discontinued Operations, Net of Tax	$ —	$ —	$ 13.4	$ —	$ 13.4
Net Income (Loss)	$ 376.3	$ 169.8	$ 525.9	$ (545.8)	$ 526.2
Capital Expenditures	$ 792.2	$ 31.2	$ 7.4	$ —	$ 830.8
Total Assets (c)	$ 13,433.5	$ 2,949.0	$ 4,694.8	$ (7,215.2)	$ 13,862.1

Year Ended	Reportable Segments: Energy: Utility	Reportable Segments: Energy: Non-Utility	Corporate & Other (a)	Eliminations & Reconciling Items	Total Consolidated
	(Millions of Dollars)				
December 31, 2010					
Operating Revenues (b)	$ 4,165.3	$ 320.2	$ 0.5	$ (283.5)	$ 4,202.5
Depreciation and Amortization	$ 251.4	$ 53.5	$ 0.7	$ —	$ 305.6
Operating Income (Loss)	$ 564.0	$ 252.4	$ (6.0)	$ —	$ 810.4
Equity in Earnings of Unconsolidated Affiliates	$ 60.1	$ —	$ (0.2)	$ —	$ 59.9
Interest Expense, Net	$ 117.2	$ 40.3	$ 52.8	$ (3.9)	$ 206.4
Income Tax Expense (Benefit)	$ 192.1	$ 84.9	$ (27.1)	$ —	$ 249.9
Income from Discontinued Operations, Net of Tax	$ 0.7	$ —	$ 1.4	$ —	$ 2.1
Net Income (Loss)	$ 354.2	$ 128.4	$ 456.4	$ (482.5)	$ 456.5
Capital Expenditures	$ 687.0	$ 109.3	$ 1.9	$ —	$ 798.2
Total Assets (c)	$ 11,997.4	$ 2,914.2	$ 5,075.9	$ (6,927.7)	$ 13,059.8

(a) Corporate & 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 is included in Operating Revenues. This elimination is primarily between We Power and Wisconsin Electric.

(c) An elimination of $2,286.7 million, $2,369.0 million and $1,785.9 million is included in Total Assets as of December 31, 2012, 2011 and 2010, respectively, for all PTF-related activity between We Power and Wisconsin Electric.

O -- RELATED PARTIES

We receive and/or provide certain services to other associated companies in which we have an equity investment.

American Transmission Company LLC: As of December 31, 2012, we have a 26.2% interest in ATC. We pay ATC for transmission and other related services it provides. In addition, we provide a variety of operational, maintenance and project management work for ATC, which are reimbursed to us by ATC. We are required to pay the cost of needed transmission infrastructure upgrades for new generation projects while projects are under construction, including the new generating units constructed as part of our PTF strategy. ATC reimburses us for these costs when new generation is placed in service. As of December 31, 2012 and 2011, we had a receivable of zero and $5.4 million, respectively, for these items. During the years ended December 31, 2012, 2011 and 2010, our equity in earnings from ATC was $65.7 million, $62.5 million and $60.1 million, respectively. During the years ended December 31, 2012, 2011 and 2010, distributions received from ATC were $52.6 million, $49.7 million and $49.3 million, respectively.

We provided and received services from the following associated companies during 2012, 2011 and 2010:

Equity Investee	2012	2011	2010
	(Millions of Dollars)		
Services Provided			
–ATC	$ 8.2	$ 10.8	$ 16.9
Services Received			
–ATC	$ 222.7	$ 219.2	$ 220.8

As of December 31, 2012 and 2011, our Consolidated Balance Sheets included receivable and payable balances with ATC as follows:

Equity Investee	2012	2011
	(Millions of Dollars)	
Services Provided		
–ATC	$ 0.5	$ 0.7
Services Received		
–ATC	$ 18.6	$ 18.1

P -- COMMITMENTS AND CONTINGENCIES

Capital Expenditures: We have made certain commitments in connection with 2013 capital expenditures. During 2013, we estimate that total capital expenditures will be approximately $692.7 million.

Operating Leases: We enter into long-term purchase power contracts to meet a portion of our anticipated increase in future electric energy supply needs. These contracts expire at various times through 2018. Certain of these contracts were deemed to qualify as operating leases. In addition, we have various other operating leases including leases for coal cars.

Future minimum payments for the next five years and thereafter for our operating lease contracts are as follows:

	(Millions of Dollars)
2013	$ 6.5
2014	3.9
2015	3.9
2016	3.7
2017	3.2
Thereafter	25.9
Total	$ 47.1

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

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 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 $16 million to $62 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 December 31, 2012 and 2011, we established reserves of $38.2 million and $37.5 million, respectively, 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.

Coal Combustion Product Landfill Sites: Wisconsin Electric aggressively seeks environmentally acceptable, beneficial uses for its coal combustion products. However, some coal combustion products have been, and to a small degree continue to be, managed in company-owned, licensed landfills. Some early designed and constructed landfills have at times required various levels of monitoring or remediation. Where Wisconsin Electric has become aware of these conditions, efforts have been made to define the nature and extent of any release, and work has been performed to address these conditions. During 2012, 2011 and 2010, Wisconsin Electric incurred $0.3 million, $0.2 million and $0.4 million respectively, in landfill remediation expenses. As of December 31, 2012, we have no reserves established related to coal combustion product landfill sites.

EPA - Consent Decree: In April 2003, Wisconsin Electric reached a Consent Decree with the EPA, in which it agreed to significantly reduce air emissions from its coal-fired generating facilities. In July 2003, the Consent Decree was amended to include the state of Michigan, and in October 2007, the U.S. District Court for the Eastern District of Wisconsin approved and entered the amended Consent Decree. The Consent Decree was further amended in January 2012 to change the point of air monitoring at the Oak Creek Power Plant to accommodate the AQCS that began service in 2012. In order to achieve the reductions agreed to in the Consent

Decree, over the past almost 10 years we have installed new pollution control equipment, including the Oak Creek AQCS, upgraded existing equipment and retired certain older coal units at a cost of approximately $1.2 billion. We estimate we will spend an additional $22 million in 2013 for final implementation costs.

Valley Power Plant Title V Air Permit: The WDNR renewed VAPP's 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; however, the case has been stayed. In addition, in March 2011, the Sierra Club petitioned the 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.

In August 2012, we announced plans to convert the fuel source for VAPP from coal to natural gas and anticipate that the conversion will be completed by the end of 2015 or early 2016. We currently expect the cost of this conversion to be between $60 million and $65 million subject to PSCW approval, and receiving a construction permit from the WDNR. We expect to file for a Certificate of Authority from the PSCW and an air permit from the WDNR during the second quarter of 2013.

We have made significant progress on the four voluntary goals that we submitted in a December 2011 letter to the EPA: (1) we achieved the reductions in annual 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 eliminates the requirement to meet the 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 2015-2016, provided that we can obtain authorization from the PSCW to do so.

Cash Balance Pension Plan: In June 2009, a lawsuit was filed by Alan M. Downes, a former employee, against the Plan in the U.S. District Court for the Eastern District of Wisconsin. 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 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 2010. The court approved the settlement and issued its written order in April 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.

Q -- SUPPLEMENTAL CASH FLOW INFORMATION

During the year ended December 31, 2012, we paid $241.2 million in interest, net of amounts capitalized, and received $107.0 million in net refunds from income taxes. During the year ended December 31, 2011, we paid $234.0 million in interest, net of amounts capitalized, and received $109.1 million in net refunds from income taxes. During the year ended December 31, 2010, we paid $198.0 million in interest, net of amounts capitalized, and paid $166.7 million in income taxes, net of refunds.

As of December 31, 2012, 2011 and 2010, the amount of accounts payable related to capital expenditures was $15.7 million, $16.7 million and $18.2 million, respectively.

During the years ended December 31, 2012, 2011 and 2010, total amortization of deferred revenue was $54.9 million, $54.4 million and $34.6 million, respectively.

Deloitte.

Deloitte & Touche LLP
555 E. Wells Street, Suite 1400
Milwaukee, WI 53202-3824
USA

Tel: 414-271-3000
Fax: 414-347-6200
www.deloitte.com

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Wisconsin Energy Corporation:

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Wisconsin Energy Corporation and subsidiaries (the "Company") as of December 31, 2012 and 2011, and the related consolidated statements of income, common equity, and cash flows for each of the three years in the period ended December 31, 2012. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Wisconsin Energy Corporation and subsidiaries as of December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2012, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2013 expressed an unqualified opinion on the Company's internal control over financial reporting.

Deloitte & Touche LLP

February 27, 2013

Deloitte.

Deloitte & Touche LLP
555 E. Wells Street, Suite 1400
Milwaukee, WI 53202-3824
USA

Tel: 414-271-3000
Fax: 414-347-6200
www.deloitte.com

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Wisconsin Energy Corporation:

We have audited the internal control over financial reporting of Wisconsin Energy Corporation and subsidiaries (the "Company") as of December 31, 2012, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2012 of the Company and our report dated February 27, 2013 expressed an unqualified opinion on those financial statements.

Deloitte & Touche LLP

February 27, 2013

Member of
Deloitte Touche Tohmatsu

INTERNAL CONTROL OVER FINANCIAL REPORTING

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of Wisconsin Energy Corporation's and subsidiaries' internal control over financial reporting based on the framework in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its evaluation, our management concluded that Wisconsin Energy Corporation's and subsidiaries' internal control over financial reporting was effective as of December 31, 2012.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of the effectiveness of internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Deloitte & Touche LLP, an independent registered public accounting firm, as auditors of our financial statements has issued an attestation report on the effectiveness of Wisconsin Energy Corporation's and its subsidiaries' internal control over financial reporting as of December 31, 2012. Deloitte & Touche LLP's report is included in this report.

Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting during the fourth quarter of 2012 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

WISCONSIN ENERGY CORPORATION
CONSOLIDATED SELECTED FINANCIAL AND STATISTICAL DATA

Financial	2012	2011	2010	2009	2008
Year Ended December 31					
Net income - Continuing Operations (Millions)	$ 546.3	$ 512.8	$ 454.4	$ 375.7	$ 355.1
Earnings per share - Continuing Operations					
Basic	$ 2.37	$ 2.20	$ 1.94	$ 1.61	$ 1.52
Diluted	$ 2.35	$ 2.18	$ 1.92	$ 1.59	$ 1.50
Dividends per share of common stock	$ 1.20	$ 1.04	$ 0.80	$ 0.675	$ 0.54
Operating revenues (Millions)					
Utility energy	$ 4,190.8	$ 4,431.5	$ 4,165.3	$ 4,092.0	$ 4,395.5
Non-utility energy	439.9	435.1	320.2	163.1	126.2
Eliminations and Other	(384.3)	(380.2)	(283.0)	(154.2)	(119.3)
Total operating revenues	$ 4,246.4	$ 4,486.4	$ 4,202.5	$ 4,100.9	$ 4,402.4
As of December 31 (Millions)					
Total assets	$ 14,285.0	$ 13,862.1	$ 13,059.8	$ 12,697.9	$ 12,617.8
Long-term debt (including current maturities) and capital lease obligations	$ 4,865.9	$ 4,646.9	$ 4,405.4	$ 4,171.5	$ 4,136.5
Common Stock Closing Price	$ 36.85	$ 34.96	$ 29.43	$ 24.92	$ 20.99

CONSOLIDATED SELECTED QUARTERLY FINANCIAL DATA

	(Millions of Dollars, Except Per Share Amounts) (a)			
	March		June	
Three Months Ended	2012	2011	2012	2011
Operating revenues	$ 1,191.2	$ 1,328.7	$ 944.7	$ 991.7
Operating income	295.7	295.6	222.6	174.4
Income from Continuing Operations	172.1	170.9	119.3	98.0
Income from Discontinued Operations	—	—	—	11.5
Total Net Income	$ 172.1	$ 170.9	$ 119.3	$ 109.5
Earnings per share of common stock (basic) (b)				
Continuing operations	$ 0.75	$ 0.73	$ 0.52	$ 0.42
Discontinued operations	—	—	—	0.05
Total earnings per share (basic)	$ 0.75	$ 0.73	$ 0.52	$ 0.47
Earnings per share of common stock (diluted) (b)				
Continuing operations	$ 0.74	$ 0.72	$ 0.51	$ 0.41
Discontinued operations	—	—	—	0.05
Total earnings per share (diluted)	$ 0.74	$ 0.72	$ 0.51	$ 0.46

	September		December	
Three Months Ended	2012	2011	2012	2011
Operating revenues	$ 1,039.3	$ 1,052.8	$ 1,071.2	$ 1,113.2
Operating income	280.6	224.3	201.4	193.0
Income from Continuing Operations	156.1	129.8	98.8	114.1
Income from Discontinued Operations	—	—	—	1.9
Total Net Income	$ 156.1	$ 129.8	$ 98.8	$ 116.0
Earnings per share of common stock (basic) (b)				
Continuing operations	$ 0.68	$ 0.56	$ 0.43	$ 0.49
Discontinued operations	—	—	—	0.01
Total earnings per share (basic)	$ 0.68	$ 0.56	$ 0.43	$ 0.50
Earnings per share of common stock (diluted) (b)				
Continuing operations	$ 0.67	$ 0.55	$ 0.43	$ 0.49
Discontinued operations	—	—	—	0.01
Total earnings per share (diluted)	$ 0.67	$ 0.55	$ 0.43	$ 0.50

(a) Quarterly results of operations are not directly comparable because of seasonal and other factors. See Management's Discussion and Analysis of Financial Condition and Results of Operations.

(b) Quarterly earnings per share may not total to the amounts reported for the year because the computation is based on the weighted average common shares outstanding during each quarter.

PERFORMANCE GRAPH

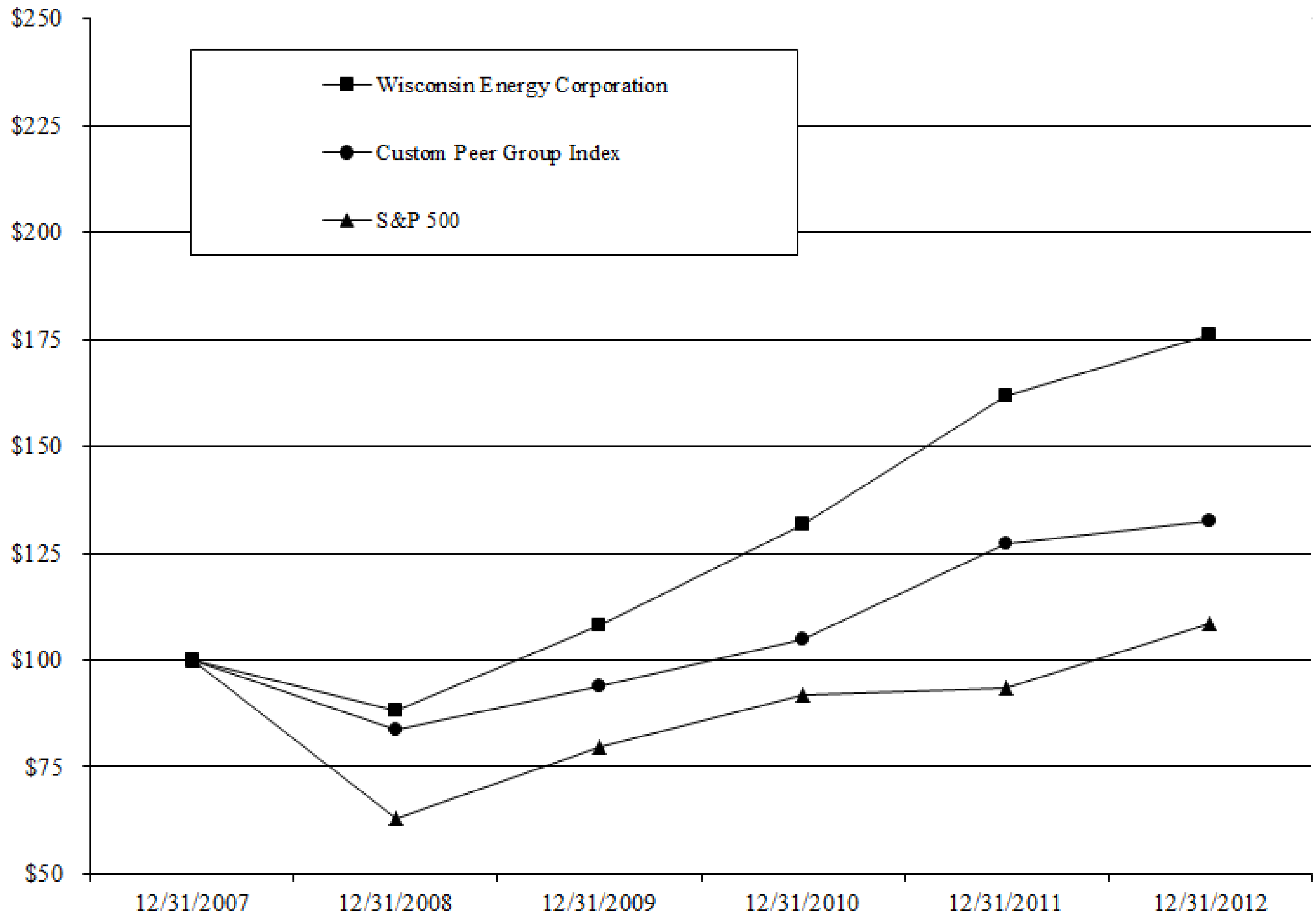
The performance graph on the next page shows a comparison of the cumulative total return, assuming reinvestment of dividends, over the last five years had $100 been invested at the close of business on December 31, 2007, in each of:

- Wisconsin Energy common stock;
- a Custom Peer Group Index; and
- the Standard & Poor's 500 Index ("S&P 500").

Custom Peer Group Index. We use the Custom Peer Group Index for peer comparison purposes because we believe the Index provides an accurate representation of our peers. The Custom Peer Group Index is a market-capitalization-weighted index consisting of 27 companies, including Wisconsin Energy. These companies are similar to us in terms of business model and long-term strategies.

In addition to Wisconsin Energy, the companies in the Custom Peer Group Index are Allegheny Energy Inc.; Alliant Energy Corporation; Ameren Corporation; American Electric Power Company, Inc.; Avista Corporation; Consolidated Edison, Inc.; DTE Energy Company; Duke Energy Corp.; FirstEnergy Corp.; Great Plains Energy, Inc.; Integrys Energy Group, Inc.; NiSource Inc.; Northeast Utilities; NStar; NV Energy, Inc.; OGE Energy Corp.; Pepco Holdings, Inc.; PG&E Corporation; Pinnacle West Capital Corporation; Portland General; Progress Energy Inc.; SCANA Corporation; Sempra Energy; The Southern Company; Westar Energy, Inc.; and Xcel Energy Inc.

Five-Year Cumulative Return Chart



Value of Investment at Year-End

	12/31/07	12/31/08	12/31/09	12/31/10	12/31/11	12/31/12
Wisconsin Energy Corporation	$100	$88	$108	$132	$162	$176
Custom Peer Group Index	$100	$84	$94	$105	$127	$133
S&P 500	$100	$63	$80	$92	$94	$109

MARKET FOR OUR COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

NUMBER OF COMMON STOCKHOLDERS

As of December 31, 2012, based upon the number of Wisconsin Energy Corporation stockholder accounts (including accounts in our dividend reinvestment and stock purchase plan), we had approximately 41,300 registered stockholders.

COMMON STOCK LISTING AND TRADING

Our common stock is listed on the New York Stock Exchange under the ticker symbol "WEC." Daily trading prices and volume can be found in the "NYSE Composite" section of most major newspapers, usually abbreviated as WI Engy.

DIVIDENDS AND COMMON STOCK PRICES

Common Stock Dividends of Wisconsin Energy: Cash dividends on our common stock, as declared by the Board of Directors, are normally paid on or about the first day of March, June, September and December of each year. We review our dividend policy on a regular basis. Subject to any regulatory restrictions or other limitations on the payment of dividends, future dividends will be at the discretion of the Board of Directors and will depend upon, among other factors, earnings, financial condition and other requirements. For information regarding restrictions on the ability of our subsidiaries to pay us dividends, see Note H -- Common Equity in the Notes to Consolidated Financial Statements.

On January 17, 2013, our Board of Directors affirmed our dividend policy that targets a dividend payout ratio of 60% in the year 2014, and approved a new dividend policy that targets a payout ratio that trends to 65-70% in 2017. In accordance with that policy, on January 17, 2013, our Board of Directors increased our quarterly dividend to $0.34 per share effective with the first quarter 2013 dividend payment, which would result in annual dividends of $1.36 per share.

Range of Wisconsin Energy Common Stock Prices and Dividends:

	2012			2011		
Quarter	High	Low	Dividend	High	Low	Dividend
First	$ 35.35	$ 33.62	$ 0.30	$ 31.01	$ 28.83	$ 0.26
Second	$ 40.00	$ 34.54	0.30	$ 31.89	$ 29.39	0.26
Third	$ 41.48	$ 37.46	0.30	$ 32.49	$ 27.00	0.26
Fourth	$ 38.93	$ 36.01	0.30	$ 35.38	$ 29.82	0.26
Annual	$ 41.48	$ 33.62	$ 1.20	$ 35.38	$ 27.00	$ 1.04

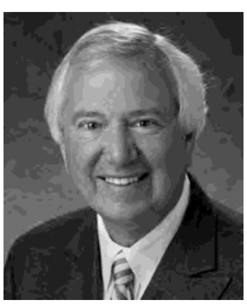
BOARD OF DIRECTORS

John F. Bergstrom
Director since 1987.
Chairman and Chief Executive Officer of Bergstrom Corporation, which owns and operates numerous automobile sales and leasing companies.

Barbara L. Bowles
Director since 1998.
Retired Vice Chair of Profit Investment Management and Retired Chairman of The Kenwood Group, Inc., investment advisory firms. The Kenwood Group, Inc. was merged into Profit Investment Management in 2006.

Patricia W. Chadwick
Director since 2006.
President of Ravengate Partners, LLC, which provides businesses and not-for-profit institutions with advice about the economy and the financial markets.

Robert A. Cornog
Director since 1993.
Retired Chairman, President and Chief Executive Officer of Snap-on Incorporated, a developer, manufacturer and distributor of professional hand and power tools, diagnostic and shop equipment and tool storage products.



Curt S. Culver
Director since 2004.
Chairman and Chief Executive Officer of MGIC Investment Corporation and Mortgage Guaranty Insurance Corporation, a private mortgage insurance company.

Thomas J. Fischer
Director since 2005.
Principal of Fischer Financial Consulting LLC, which provides consulting on corporate financial, accounting and governance matters.

Gale E. Klappa
Director since 2003.
Chairman, President and Chief Executive Officer of Wisconsin Energy Corporation.

Henry W. Knueppel
Director since 2013.
Retired Chairman and Chief Executive Officer of Regal Beloit Corporation, a manufacturer of electrical and mechanical motion control products.

Ulice Payne, Jr.
Director since 2003.
Managing Member of Addison-Clifton, LLC, which provides global trade compliance advisory services.

Mary Ellen Stanek
Director since 2012.
Managing Director and Director of Asset Management of Baird Financial Group; Chief Investment Officer, Baird Advisors; President, Baird Funds, Inc. Baird Financial Group provides wealth management, capital markets, private equity and asset management services to clients worldwide.

OFFICERS

The names and positions as of December 31, 2012 of Wisconsin Energy's officers are listed below.

Gale E. Klappa[1] – Chairman of the Board, President and Chief Executive Officer.

J. Patrick Keyes[1][2] – Executive Vice President, Chief Financial Officer and Treasurer.

Frederick D. Kuester[1][3] – Executive Vice President.

Allen L. Leverett[1] – Executive Vice President.

Susan H. Martin[1] – Executive Vice President, General Counsel and Corporate Secretary.

Robert M. Garvin[1] – Senior Vice President – External Affairs.

Kristine A. Rappé[1][4] – Senior Vice President and Chief Administrative Officer.

Darnell K. DeMasters – Vice President – Federal Policy.

Stephen P. Dickson[1] – Vice President and Controller.

Walter J. Kunicki – Vice President.

Richard J. White – Vice President.

Keith H. Ecke – Assistant Corporate Secretary.

David L. Hughes – Assistant Treasurer.

Scott J. Lauber[2] – Assistant Treasurer.

James A. Schubilske[5] – Assistant Treasurer.

[1] Executive Officers of Wisconsin Energy Corporation as of December 31, 2012. Kevin Fletcher, Senior Vice President of Wisconsin Electric Power Company and Wisconsin Gas LLC, is also an executive officer of Wisconsin Energy Corporation.

[2] Mr. Keyes stepped down as Treasurer effective January 31, 2013. Mr. Lauber was appointed Vice President and Treasurer effective February 1, 2013.

[3] Mr. Kuester retired effective January 4, 2013.

[4] Ms. Rappé concluded her employment effective February 28, 2013.

[5] Effective February 1, 2013, Mr. Schubilske was appointed Vice President – State Regulatory Affairs, an officer position with Wisconsin Electric Power Company and Wisconsin Gas LLC.

STOCKHOLDER INFORMATION

ACCOUNT INFORMATION

- Visit **www.computershare.com/investor**(1). Wisconsin Energy's transfer agent, Computershare, provides our registered stockholders with secure account access. Stockholders can view share balances, market value, tax documents and account statements; review answers to frequently asked questions; perform many transactions; and sign up for eDelivery, the paperless communication program that also features electronic delivery of your annual meeting materials.

- Write to(2):
  Wisconsin Energy Corporation
  c/o Computershare
  P.O. Box 43006
  Providence, RI 02940-3006

- Call Computershare at **800-558-9663**. Service representatives are available from 7 a.m. to 7 p.m. Central time on business days. An automated voice-response system also provides information 24 hours a day, seven days a week.

Securities analysts and institutional investors may contact our Investor Relations Line at **414-221-2592**. Stockholders who hold Wisconsin Energy stock in brokerage accounts should contact their brokerage firm.

STOCK PURCHASE PLAN

Wisconsin Energy's Stock Plus Investment Plan provides a convenient way to purchase our common stock and reinvest dividends. To review the Prospectus and enroll, go to **wisconsinenergy.com** and select the Investors tab. You also may contact Computershare at **800-558-9663** to request an enrollment package. This is not an offer to sell, or a solicitation of an offer to buy, any securities. Any stock offering will be made only by Prospectus.

DIVIDENDS

Dividends, as declared by the board of directors, typically are payable on the first day of March, June, September and December. Stockholders may have their dividends deposited directly into their bank accounts. Contact Computershare to request an authorization form.

INTERNET ACCESS HELPS REDUCE COSTS

You may access **wisconsinenergy.com** for the latest information about Wisconsin Energy Corporation. The site provides access to financial, corporate governance and other information, including Securities and Exchange Commission reports.

ANNUAL CERTIFICATIONS

Wisconsin Energy has filed the required certifications of its Chief Executive Officer and Chief Financial Officer under the Sarbanes-Oxley Act regarding the quality of its public disclosures. These exhibits can be found in the company's Form 10-K for the year ended Dec. 31, 2012. The certification of Wisconsin Energy's Chief Executive Officer regarding compliance with the New York Stock Exchange (NYSE) corporate governance listing standards will be filed with the NYSE following the 2013 Annual Meeting of Stockholders. Last year, we filed this certification on May 25, 2012.

CORPORATE GOVERNANCE

Wisconsin Energy has a long tradition of sound corporate governance practices. The company continues to rank at or near the top of more than 4,300 companies worldwide that are assessed by GovernanceMetrics International, an independent rating agency. Over the most recent eight-year period, Wisconsin Energy earned a 'perfect 10' rating 31 out of 32 times — the only company to achieve this distinction.

CORPORATE SOCIAL RESPONSIBILITY

Wisconsin Energy is committed to corporate social responsibility and sustainable business practices — aligning our policies and practices with the needs of key stakeholders, and managing risk while accounting for the company's economic, environmental and social impacts. For additional information, visit **www.wisconsinenergy.com/csr.**

Wisconsin Energy Corporation

(1) Computershare recently acquired the transfer agent services of BNY Mellon. For a brief period of time, it may be necessary to access your account at www.bnymellon.com/shareowner/equity.

(2) If sending overnight correspondence, mail to: Wisconsin Energy Corporation, c/o Computershare, 250 Royall Street, Canton, MA 02021-1011.

Wisconsin Energy Corporation

231 W. MICHIGAN ST.

P.O. BOX 1331

MILWAUKEE, WI 53201

414-221-2345

wisconsinenergy.com

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