UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

[X] Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the quarterly period ended September 30, 2011

or

[ ] Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the transition period from ______ to _______

Commission File Number	Exact name of registrant as specified in its charter; State or other jurisdiction of incorporation or organization	IRS Employer Identification No.
001-14881	**MIDAMERICAN ENERGY HOLDINGS COMPANY** **(An Iowa Corporation)** **666 Grand Avenue, Suite 500** **Des Moines, Iowa 50309-2580** **515-242-4300**	**94-2213782**

N/A

(Former name, former address and former fiscal year, if changed since last report)

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

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

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

Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☒ Smaller reporting company ☐

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

All of the shares of common equity of MidAmerican Energy Holdings Company are privately held by a limited group of investors. As of October 31, 2011, 74,609,001 shares of common stock were outstanding.

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PART I

PART II

Definition of Abbreviations and Industry Terms

When used in Part I, Items 2 through 4, and Part II, Items 1 through 6, the following terms have the definitions indicated.

MidAmerican Energy Holdings Company and Related Entities

MEHC	MidAmerican Energy Holdings Company
Company	MidAmerican Energy Holdings Company and its subsidiaries
MidAmerican Funding	MidAmerican Funding, LLC
MidAmerican Energy	MidAmerican Energy Company
Northern Natural Gas	Northern Natural Gas Company
Kern River	Kern River Gas Transmission Company
Northern Powergrid Holdings	Northern Powergrid Holdings Company
CE Casecnan	CE Casecnan Water and Energy Company, Inc.
HomeServices	HomeServices of America, Inc. and its subsidiaries
ETT	Electric Transmission Texas, LLC
Utilities	PacifiCorp and MidAmerican Energy Company

Certain Industry Terms

AFUDC	Allowance for Funds Used During Construction
CSAPR	Cross-State Air Pollution Rule
EBA	Energy Balancing Account
ECAM	Energy Cost Adjustment Mechanism
EPA	United States Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gases
GHG Reporting	Greenhouse Gases Reporting
IPUC	Idaho Public Utilities Commission
IUB	Iowa Utilities Board
kV	Kilovolt
Mine Safety Act	Federal Mine Safety and Health Act of 1977
MISO	Midwest Independent Transmission System Operator, Inc.
MSHA	Federal Mine Safety and Health Administration
MW	Megawatts
NRC	Nuclear Regulatory Commission
OPUC	Oregon Public Utility Commission
PCAM	Power Cost Adjustment Mechanism
RCRA	Resource Conservation and Recovery Act
REC	Renewable Energy Credit
RPS	Renewable Portfolio Standards
SIP	State Implementation Plan
TAM	Transition Adjustment Mechanism
UPSC	Utah Public Service Commission
WPSC	Wyoming Public Service Commission
WUTC	Washington Utilities and Transportation Commission

Forward-Looking Statements

This report contains statements that do not directly or exclusively relate to historical facts. These statements 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. Forward-looking statements can typically be identified by the use of forward-looking words, such as "will," "may," "could," "project," "believe," "anticipate," "expect," "estimate," "continue," "intend," "potential," "plan," "forecast" and similar terms. These statements are based upon the Company's current intentions, assumptions, expectations and beliefs and are subject to risks, uncertainties and other important factors. Many of these factors are outside the control of the Company and could cause actual results to differ materially from those expressed or implied by such forward-looking statements. These factors include, among others:

- general economic, political and business conditions, as well as changes in laws and regulations affecting the Company's operations or related industries;
- changes in, and compliance with, environmental laws, regulations, decisions and policies that could, among other items, increase operating and capital costs, reduce generating facility output, accelerate generating facility retirements or delay generating facility construction or acquisition;
- the outcome of general rate cases and other proceedings conducted by regulatory commissions or other governmental and legal bodies;
- changes in economic, industry, competition or weather conditions, as well as demographic trends, that could affect customer growth and usage, electricity and natural gas supply or the Company's ability to obtain long-term contracts with customers and suppliers;
- a high degree of variance between actual and forecasted load that could impact the Company's hedging strategy and the cost of balancing its generation resources and wholesale activities with its retail load obligations;
- performance and availability of the Company's generating facilities, including the impacts of outages and repairs, transmission constraints, weather and operating conditions;
- changes in prices, availability and demand for both purchases and sales of wholesale electricity, coal, natural gas, other fuel sources and fuel transportation that could have a significant impact on generating capacity and energy costs;
- the financial condition and creditworthiness of the Company's significant customers and suppliers;
- changes in business strategy or development plans;
- availability, terms and deployment of capital, including reductions in demand for investment-grade commercial paper, debt securities and other sources of debt financing and volatility in the London Interbank Offered Rate, the base interest rate for MEHC's and its subsidiaries' credit facilities;
- changes in MEHC's and its subsidiaries' credit ratings;
- risks relating to nuclear generation;
- the impact of derivative contracts used to mitigate or manage volume, price and interest rate risk, including increased collateral requirements, and changes in commodity prices, interest rates and other conditions that affect the fair value of derivative contracts;
- the impact of inflation on costs and our ability to recover such costs in regulated rates;
- increases in employee healthcare costs;
- the impact of investment performance and changes in interest rates, legislation, healthcare cost trends, mortality and morbidity on pension and other postretirement benefits expense and funding requirements;
- changes in the residential real estate brokerage and mortgage industries and regulations that could affect brokerage and mortgage transaction levels;
- unanticipated construction delays, changes in costs, receipt of required permits and authorizations, ability to fund capital projects and other factors that could affect future generating facilities and infrastructure additions;
- the availability and price of natural gas in applicable geographic regions;
- the impact of new accounting guidance or changes in current accounting estimates and assumptions on the Company's consolidated financial results;
- the Company's ability to successfully integrate future acquired operations into its business;

- other risks or unforeseen events, including the effects of storms, floods, litigation, wars, terrorism, embargoes and other catastrophic events; and
- other business or investment considerations that may be disclosed from time to time in MEHC's filings with the United States Securities and Exchange Commission or in other publicly disseminated written documents.

Further details of the potential risks and uncertainties affecting the Company are described in MEHC's filings with the United States Securities and Exchange Commission, including Part II, Item 1A and other discussions contained in this Form 10-Q. The Company undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The foregoing review of factors should not be construed as exclusive.

PART I

Item 1. Financial Statements

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
MidAmerican Energy Holdings Company
Des Moines, Iowa

We have reviewed the accompanying consolidated balance sheet of MidAmerican Energy Holdings Company and subsidiaries (the "Company") as of September 30, 2011, and the related consolidated statements of operations and comprehensive income for the three-month and nine-month periods ended September 30, 2011 and 2010, and of cash flows and changes in equity for the nine-month periods ended September 30, 2011 and 2010. These interim financial statements are the responsibility of the Company's management.

We conducted our reviews in accordance with the standards of the Public Company Accounting Oversight Board (United States). A review of interim financial information consists principally of applying analytical procedures and making inquiries of persons responsible for financial and accounting matters. It is substantially less in scope than an audit conducted in accordance with the standards of the Public Company Accounting Oversight Board (United States), the objective of which is the expression of an opinion regarding the financial statements taken as a whole. Accordingly, we do not express such an opinion.

Based on our reviews, we are not aware of any material modifications that should be made to such consolidated interim financial statements for them to be in conformity with accounting principles generally accepted in the United States of America.

We have previously audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheet of MidAmerican Energy Holdings Company and subsidiaries as of December 31, 2010, and the related consolidated statements of operations, cash flows, changes in equity, and comprehensive income for the year then ended (not presented herein); and in our report dated February 28, 2011, we expressed an unqualified opinion on those consolidated financial statements. In our opinion, the information set forth in the accompanying consolidated balance sheet as of December 31, 2010 is fairly stated, in all material respects, in relation to the consolidated balance sheet from which it has been derived.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
November 4, 2011

MIDAMERICAN ENERGY HOLDINGS COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (Unaudited)
(Amounts in millions)

	As of	
	September 30, 2011	**December 31, 2010**
ASSETS		
Current assets:		
Cash and cash equivalents	$ 906	$ 470
Trade receivables, net	1,149	1,225
Income taxes receivable	55	396
Inventories	643	585
Derivative contracts	46	131
Investments and restricted cash and investments	65	44
Other current assets	408	437
Total current assets	3,272	3,288
Property, plant and equipment, net	33,323	31,899
Goodwill	5,005	5,025
Investments and restricted cash and investments	1,068	1,881
Regulatory assets	2,537	2,497
Derivative contracts	13	13
Other assets	1,184	1,065
Total assets	$ 46,402	$ 45,668

The accompanying notes are an integral part of these consolidated financial statements.

MIDAMERICAN ENERGY HOLDINGS COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS (Unaudited) (continued)
(Amounts in millions)

	As of	
	September 30, 2011	December 31, 2010
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$ 806	$ 827
Accrued employee expenses	208	159
Accrued interest	341	341
Accrued property, income and other taxes	353	287
Derivative contracts	155	158
Short-term debt	—	320
Current portion of long-term debt	1,321	1,286
Other current liabilities	439	424
Total current liabilities	3,623	3,802
Regulatory liabilities	1,731	1,664
Derivative contracts	332	458
MEHC senior debt	5,113	5,371
MEHC subordinated debt	151	172
Subsidiary debt	13,331	12,662
Deferred income taxes	6,518	6,298
Other long-term liabilities	1,677	1,833
Total liabilities	32,476	32,260
Commitments and contingencies (Note 12)		
Equity:		
MEHC shareholders' equity:		
Common stock - 115 shares authorized, no par value, 75 shares issued and outstanding	—	—
Additional paid-in capital	5,423	5,427
Retained earnings	8,958	7,979
Accumulated other comprehensive loss, net	(628)	(174)
Total MEHC shareholders' equity	13,753	13,232
Noncontrolling interests	173	176
Total equity	13,926	13,408
Total liabilities and equity	$ 46,402	$ 45,668

The accompanying notes are an integral part of these consolidated financial statements.

MIDAMERICAN ENERGY HOLDINGS COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS (Unaudited)
(Amounts in millions)

	Three-Month Periods Ended September 30,		Nine-Month Periods Ended September 30,	
	2011	2010	2011	2010
Operating revenue:				
Energy	$ 2,535	$ 2,510	$ 7,546	$ 7,537
Real estate	285	253	764	793
Total operating revenue	2,820	2,763	8,310	8,330
Operating costs and expenses:				
Energy:				
Cost of sales	897	976	2,709	2,956
Operating expense	604	577	1,865	1,799
Depreciation and amortization	324	316	988	939
Real estate	267	250	739	773
Total operating costs and expenses	2,092	2,119	6,301	6,467
Operating income	728	644	2,009	1,863
Other income (expense):				
Interest expense	(301)	(309)	(907)	(923)
Capitalized interest	13	14	31	42
Interest and dividend income	2	4	11	24
Other, net	17	33	63	89
Total other income (expense)	(269)	(258)	(802)	(768)
Income before income tax expense and equity income	459	386	1,207	1,095
Income tax expense	68	38	255	165
Equity income	28	24	42	29
Net income	419	372	994	959
Net income attributable to noncontrolling interests	7	8	15	100
Net income attributable to MEHC	$ 412	$ 364	$ 979	$ 859

The accompanying notes are an integral part of these consolidated financial statements.

MIDAMERICAN ENERGY HOLDINGS COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS (Unaudited)
(Amounts in millions)

	Nine-Month Periods Ended September 30, 2011	2010
Cash flows from operating activities:		
Net income	$ 994	$ 959
Adjustments to reconcile net income to net cash flows from operating activities:		
Loss (gain) on other items, net	5	(52)
Depreciation and amortization	997	950
Changes in regulatory assets and liabilities	(7)	25
Deferred income taxes and amortization of investment tax credits	475	572
Other, net	(59)	(32)
Changes in other operating assets and liabilities:		
Trade receivables and other assets	60	174
Derivative collateral, net	32	(93)
Contributions to pension and other postretirement benefit plans, net	(132)	(139)
Accounts payable and other liabilities	352	(284)
Net cash flows from operating activities	2,717	2,080
Cash flows from investing activities:		
Capital expenditures	(1,912)	(1,862)
Purchases of available-for-sale securities	(105)	(77)
Proceeds from sales of available-for-sale securities	102	65
Proceeds from sales of assets and business, net	8	140
Other, net	(86)	(63)
Net cash flows from investing activities	(1,993)	(1,797)
Cash flows from financing activities:		
Repayments of MEHC subordinated debt	(122)	(259)
Proceeds from subsidiary debt	790	231
Repayments of subsidiary debt	(601)	(142)
Net (repayments of) proceeds from short-term debt	(320)	55
Net purchases of common stock	—	(56)
Other, net	(36)	(19)
Net cash flows from financing activities	(289)	(190)
Effect of exchange rate changes	1	(1)
Net change in cash and cash equivalents	436	92
Cash and cash equivalents at beginning of period	470	429
Cash and cash equivalents at end of period	$ 906	$ 521

The accompanying notes are an integral part of these consolidated financial statements.

MIDAMERICAN ENERGY HOLDINGS COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY (Unaudited)
(Amounts in millions)

	MEHC Shareholders' Equity						
	Common		Additional Paid-in	Retained	Accumulated Other Comprehensive Income (Loss),	Noncontrolling	Total
	Shares	Stock	Capital	Earnings	Net	Interests	Equity
Balance at December 31, 2009	75	$ —	$ 5,453	$ 6,788	$ 335	$ 267	$ 12,843
Deconsolidation of Bridger Coal	—	—	—	—	—	(84)	(84)
Net income	—	—	—	859	—	100	959
Other comprehensive loss	—	—	—	—	(192)	—	(192)
Common stock purchases	—	—	(9)	(47)	—	—	(56)
Distributions	—	—	—	—	—	(19)	(19)
Other equity transactions	—	—	(5)	—	—	(36)	(41)
Balance at September 30, 2010	75	$ —	$ 5,439	$ 7,600	$ 143	$ 228	$ 13,410
Balance at December 31, 2010	75	$ —	$ 5,427	$ 7,979	$ (174)	$ 176	$ 13,408
Net income	—	—	—	979	—	15	994
Other comprehensive loss	—	—	—	—	(454)	—	(454)
Distributions	—	—	—	—	—	(19)	(19)
Other equity transactions	—	—	(4)	—	—	1	(3)
Balance at September 30, 2011	75	$ —	$ 5,423	$ 8,958	$ (628)	$ 173	$ 13,926

The accompanying notes are an integral part of these consolidated financial statements.

MIDAMERICAN ENERGY HOLDINGS COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (Unaudited)
(Amounts in millions)

	Three-Month Periods Ended September 30,		Nine-Month Periods Ended September 30,	
	2011	2010	2011	2010
Net income	$ 419	$ 372	$ 994	$ 959
Other comprehensive (loss) income, net of tax:				
Unrecognized amounts on retirement benefits, net of tax of $7, $-, $7 and $18	19	(23)	19	23
Foreign currency translation adjustment	(79)	123	(1)	(86)
Unrealized gains (losses) on cash flow hedges, net of tax of $2, $(14), $10 and $(12)	3	(21)	15	(18)
Unrealized (losses) gains on available-for-sale securities, net of tax of $(143), $51, $(323) and $(73)	(216)	77	(487)	(111)
Total other comprehensive (loss) income, net of tax	(273)	156	(454)	(192)
Comprehensive income	146	528	540	767
Comprehensive income attributable to noncontrolling interests	7	8	15	100
Comprehensive income attributable to MEHC	$ 139	$ 520	$ 525	$ 667

The accompanying notes are an integral part of these consolidated financial statements.

(1) General

MidAmerican Energy Holdings Company ("MEHC") is a holding company that owns subsidiaries principally engaged in energy businesses (collectively with its subsidiaries, the "Company"). MEHC is a consolidated subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway"). The balance of MEHC's common stock is owned by Mr. Walter Scott, Jr. (along with family members and related entities), a member of MEHC's Board of Directors, and Mr. Gregory E. Abel, a member of MEHC's Board of Directors and MEHC's Chairman, President and Chief Executive Officer. As of September 30, 2011, Berkshire Hathaway, Mr. Scott (along with family members and related entities) and Mr. Abel owned 89.8%, 9.4% and 0.8%, respectively, of MEHC's voting common stock.

The Company's operations are organized and managed as eight distinct platforms: PacifiCorp, MidAmerican Funding, LLC ("MidAmerican Funding") (which primarily consists of MidAmerican Energy Company ("MidAmerican Energy")), Northern Natural Gas Company ("Northern Natural Gas"), Kern River Gas Transmission Company ("Kern River"), Northern Powergrid Holdings Company ("Northern Powergrid Holdings") (which primarily consists of Northern Powergrid (Northeast) Limited and Northern Powergrid (Yorkshire) plc), CalEnergy Philippines (which owns a majority interest in the Casecnan project in the Philippines), CalEnergy U.S. (which owns interests in independent power projects in the United States), and HomeServices of America, Inc. (collectively with its subsidiaries, "HomeServices"). Through these platforms, the Company owns and operates an electric utility company in the Western United States, an electric and natural gas utility company in the Midwestern United States, two interstate natural gas pipeline companies in the United States, two electricity distribution companies in Great Britain, a diversified portfolio of independent power projects and the second largest residential real estate brokerage firm in the United States. Effective November 1, 2011, CE Electric UK Funding Company, Northern Electric Distribution Limited and Yorkshire Electricity Distribution plc changed their names to Northern Powergrid Holdings Company, Northern Powergrid (Northeast) Limited and Northern Powergrid (Yorkshire) plc, respectively.

The unaudited Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") for interim financial information and the United States Securities and Exchange Commission's rules and regulations for Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the disclosures required by GAAP for annual financial statements. Management believes the unaudited Consolidated Financial Statements contain all adjustments (consisting only of normal recurring adjustments) considered necessary for the fair presentation of the Consolidated Financial Statements as of September 30, 2011 and for the three- and nine-month periods ended September 30, 2011 and 2010. The results of operations for the three- and nine-month periods ended September 30, 2011 are not necessarily indicative of the results to be expected for the full year.

The preparation of the unaudited Consolidated Financial Statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the Consolidated Financial Statements and the reported amounts of revenue and expenses during the period. Actual results may differ from the estimates used in preparing the unaudited Consolidated Financial Statements. Note 2 of Notes to Consolidated Financial Statements included in the Company's Annual Report on Form 10-K for the year ended December 31, 2010 describes the most significant accounting policies used in the preparation of the Consolidated Financial Statements. There have been no significant changes in the Company's assumptions regarding significant accounting estimates and policies during the nine-month period ended September 30, 2011.

(2) New Accounting Pronouncements

In September 2011, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2011-09, which amends FASB Accounting Standards Codification ("ASC") Subtopic 715-80, "Compensation-Retirement Benefits-Multiemployer Plans." The amendments in this guidance require additional disclosures regarding an entity's participation in multiemployer pension plans and other postretirement benefit plans, as well as certain qualitative and quantitative disclosures regarding individually significant multiemployer pension plans. This guidance is effective for annual reporting periods ending after December 15, 2011. The Company is currently evaluating the impact of adopting this guidance on its disclosures included within Notes to Consolidated Financial Statements.

In September 2011, the FASB issued ASU No. 2011-08, which amends FASB ASC Topic 350, "Intangibles-Goodwill and Other." The amendments in this guidance provide an entity the option to assess qualitatively whether it is necessary to perform the current two-step goodwill impairment test. An entity would be required to perform step one if it determines qualitatively that it is more-likely-than-not that the fair value of a reporting unit is less than its carrying amount. Otherwise, no further testing would be required. This guidance is effective for interim and annual goodwill impairment tests performed for fiscal years beginning after December 15, 2011, and is not expected to have an impact on the Company's Consolidated Financial Statements.

In June 2011, the FASB issued ASU No. 2011-05, which amends FASB ASC Topic 220, "Comprehensive Income." ASU No. 2011-05 provides an entity with the option to present the total of comprehensive income, the components of net income and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements. Regardless of the option chosen, this guidance also requires presentation of items on the face of the financial statements that are reclassified from other comprehensive income to net income. This guidance does not change the items that must be reported in other comprehensive income, when an item of other comprehensive income must be reclassified to net income or how tax effects of each item of other comprehensive income are presented. This guidance is effective for interim and annual reporting periods beginning after December 15, 2011. The Company is currently evaluating which presentation option will be implemented.

In May 2011, the FASB issued ASU No. 2011-04, which amends FASB ASC Topic 820, "Fair Value Measurements and Disclosures." The amendments in this guidance are not intended to result in a change in current accounting. ASU No. 2011-04 requires additional disclosures relating to fair value measurements categorized within Level 3 of the fair value hierarchy, including quantitative information about unobservable inputs, the valuation process used by the entity and the sensitivity of unobservable input measurements. Additionally, entities are required to disclose the level of the fair value hierarchy for assets and liabilities that are not measured at fair value in the balance sheet, but for which disclosure of the fair value is required.This guidance is effective for interim and annual reporting periods beginning after December 15, 2011. The Company is currently evaluating the impact of adopting this guidance on its disclosures included within Notes to Consolidated Financial Statements.

In January 2010, the FASB issued ASU No. 2010-06, which amends FASB ASC Topic 820, "Fair Value Measurements and Disclosures." ASU No. 2010-06 requires disclosure of (a) the amount of significant transfers into and out of Levels 1 and 2 of the fair value hierarchy and the reasons for those transfers and (b) gross presentation of purchases, sales, issuances and settlements in the Level 3 fair value measurement rollforward. This guidance clarifies that existing fair value measurement disclosures should be presented for each class of assets and liabilities. The existing disclosures about the valuation techniques and inputs used to measure fair value for both recurring and nonrecurring fair value measurements have also been clarified to ensure such disclosures are presented for the Levels 2 and 3 fair value measurements. The Company adopted this guidance as of January 1, 2010, with the exception of the disclosure requirement to present purchases, sales, issuances and settlements gross in the Level 3 fair value measurement rollforward, which the Company adopted as of January 1, 2011. The adoption of this guidance did not have a material impact on the Company's disclosures included within Notes to Consolidated Financial Statements.

(3) Property, Plant and Equipment, Net

Property, plant and equipment, net consists of the following (in millions):

	Depreciable Life	As of September 30, 2011	As of December 31, 2010
Regulated assets:			
Utility generation, distribution and transmission system	5-85 years	$ 38,907	$ 37,643
Interstate pipeline assets	3-67 years	5,962	5,906
		44,869	43,549
Accumulated depreciation and amortization		(14,270)	(13,711)
Regulated assets, net		30,599	29,838
Nonregulated assets:			
Independent power plants	10-30 years	678	678
Other assets	3-30 years	424	419
		1,102	1,097
Accumulated depreciation and amortization		(523)	(492)
Nonregulated assets, net		579	605
Net operating assets		31,178	30,443
Construction work-in-progress		2,145	1,456
Property, plant and equipment, net		$ 33,323	$ 31,899

Substantially all of the construction work-in-progress as of September 30, 2011 and December 31, 2010 relates to the construction of regulated assets.

(4) Regulatory Matters

The following are updates to regulatory matters based upon material changes that occurred subsequent to December 31, 2010.

Rate Matters

Kern River Rate Case

In December 2009, the Federal Energy Regulatory Commission ("FERC") issued an order establishing rates for the period of Kern River's current long-term contracts ("Period One rates") and required that rates be levelized for shippers that elect to continue to take service following the expiration of their current contracts ("Period Two rates"). The FERC set all other issues related to Period Two rates for hearing. In November 2010, the FERC issued an order that denied all requests for rehearing from the FERC's December 2009 order and established that Kern River is entitled to a 100% equity capital structure in its Period Two rates. In January 2011, Kern River filed a motion for clarification on certain depreciation issues with the FERC.

In April 2011, the presiding administrative law judge issued an initial decision regarding Kern River's Period Two rates. Among other items, the administrative law judge determined the Period Two rates should be based on a return on equity of 11.55%, a capital structure of 100% equity, and a levelization period that coincides with each shipper group's uniform contract length of 10 or 15 years. The administrative law judge also determined that Kern River's regulatory asset associated with compressor engines and general plant replacements can only be recovered in a future rate case and may not be incorporated into Period Two rates at this time. Kern River filed its initial brief on exceptions in May 2011 and its brief opposing exceptions in June 2011. In July 2011, the FERC issued its order substantially adopting the presiding administrative law judge's initial decision. Kern River requested a rehearing and clarification of the order in August 2011. Kern River filed tariffs in compliance with the FERC's order in August 2011 and, following an order on compliance, again in September 2011. In late September 2011, the FERC issued a second order on compliance, accepting Kern River's tariff records establishing Period Two rates.

(5) Fair Value Measurements

The carrying value of the Company's cash, certain cash equivalents, receivables, payables, accrued liabilities and short-term borrowings approximates fair value because of the short-term maturity of these instruments. The Company has various financial assets and liabilities that are measured at fair value on the Consolidated Financial Statements using inputs from the three levels of the fair value hierarchy. A financial asset or liability classification within the hierarchy is determined based on the lowest level input that is significant to the fair value measurement. The three levels are as follows:

- Level 1 — Inputs are unadjusted quoted prices in active markets for identical assets or liabilities that the Company has the ability to access at the measurement date.

- Level 2 — Inputs 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, inputs other than quoted prices that are observable for the asset or liability and inputs that are derived principally from or corroborated by observable market data by correlation or other means (market corroborated inputs).

- Level 3 — Unobservable inputs reflect the Company's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. The Company develops these inputs based on the best information available, including its own data.

The following table presents the Company's assets and liabilities recognized on the Consolidated Balance Sheets and measured at fair value on a recurring basis (in millions):

	Input Levels for Fair Value Measurements				
	Level 1	Level 2	Level 3	Other[1]	Total
As of September 30, 2011					
Assets:					
Commodity derivatives	$ 2	$ 190	$ 14	$ (147)	$ 59
Investments in available-for-sale securities:					
Money market mutual funds[2]	561	—	—	—	561
Debt securities	83	55	35	—	173
Equity securities	593	—	—	—	593
	$ 1,239	$ 245	$ 49	$ (147)	$ 1,386
Liabilities - Commodity derivatives	$ (18)	$ (492)	$ (221)	$ 244	$ (487)
As of December 31, 2010					
Assets:					
Commodity derivatives	$ 3	$ 293	$ 23	$ (175)	$ 144
Investments in available-for-sale securities:					
Money market mutual funds[2]	301	—	—	—	301
Debt securities	74	53	50	—	177
Equity securities	1,412	—	—	—	1,412
	$ 1,790	$ 346	$ 73	$ (175)	$ 2,034
Liabilities - Commodity derivatives	$ (10)	$ (568)	$ (354)	$ 316	$ (616)

(1) Represents netting under master netting arrangements and a net cash collateral receivable of $97 million and $141 million as of September 30, 2011 and December 31, 2010, respectively.

(2) Amounts are included in cash and cash equivalents; current investments and restricted cash and investments; and noncurrent investments and restricted cash and investments on the Consolidated Balance Sheets. The fair value of these money market mutual funds approximates cost.

Derivative contracts are recorded on the Consolidated Balance Sheets as either assets or liabilities and are stated at fair value unless they are designated as normal purchases or normal sales and qualify for the exception afforded by GAAP. When available, the fair value of derivative contracts is estimated using unadjusted quoted prices for identical contracts in the market in which the Company transacts. When quoted prices for identical contracts are not available, the Company uses forward price curves. Forward price curves represent the Company's estimates of the prices at which a buyer or seller could contract today for delivery or settlement at future dates. The Company bases its forward price curves upon market price quotations, when available, or internally developed and commercial models, with internal and external fundamental data inputs. Market price quotations are obtained from independent energy brokers, exchanges, direct communication with market participants and actual transactions executed by the Company. Market price quotations for certain major electricity and natural gas trading hubs are generally readily obtainable for the applicable term of the Company's outstanding derivative contracts; therefore, the Company's forward price curves for those locations and periods reflect observable market quotes. Market price quotations for other electricity and natural gas trading hubs are not as readily obtainable due to the length of the contract. Given that limited market data exists for these contracts, as well as for those contracts that are not actively traded, the Company uses forward price curves derived from internal models based on perceived pricing relationships to major trading hubs that are based on unobservable inputs. The estimated fair value of these derivative contracts is a function of underlying forward commodity prices, interest rates, currency rates, related volatility, counterparty creditworthiness and duration of contracts. Refer to Note 6 for further discussion regarding the Company's risk management and hedging activities.

Contracts with explicit or embedded optionality are valued by separating each contract into its physical and financial forward, swap and option components. Forward and swap components are valued against the appropriate forward price curve. Option components are valued using Black-Scholes-type models, such as European option, spread option and best-of option, with the appropriate forward price curve and other inputs.

The Company's investments in money market mutual funds and debt and equity securities are accounted for as available-for-sale securities and are stated at fair value. When available, a readily observable quoted market price or net asset value of an identical security in an active market is used to record the fair value. In the absence of a quoted market price or net asset value of an identical security, the fair value is determined using pricing models or net asset values based on observable market inputs and quoted market prices of securities with similar characteristics. The fair value of the Company's investments in auction rate securities, where there is no current liquid market, is determined using pricing models based on available observable market data and the Company's judgment about the assumptions, including liquidity and nonperformance risks, which market participants would use when pricing the asset.

The following table reconciles the beginning and ending balances of the Company's assets and liabilities measured at fair value on a recurring basis using significant Level 3 inputs (in millions):

	Three-Month Period Ended September 30,		Nine-Month Period Ended September 30,	
	Commodity Derivatives	Debt Securities	Commodity Derivatives	Debt Securities
2011				
Beginning balance	$ (233)	$ 37	$ (331)	$ 50
Changes included in earnings[(1)]	6	—	10	—
Changes in fair value recognized in other comprehensive income	—	(2)	—	—
Changes in fair value recognized in net regulatory assets	4	—	87	—
Sales	—	—	—	(15)
Settlements	15	—	26	—
Transfers from Level 2	1	—	1	—
Ending balance	$ (207)	$ 35	$ (207)	$ 35
2010				
Beginning balance	$ (390)	$ 41	$ (359)	$ 46
Changes included in earnings[(1)]	10	—	15	—
Changes in fair value recognized in other comprehensive income	—	—	—	(5)
Changes in fair value recognized in net regulatory assets	14	—	(35)	—
Purchases, sales, issuances and settlements	36	—	49	—
Transfers to Level 2	3	—	3	—
Ending balance	$ (327)	$ 41	$ (327)	$ 41

(1) Changes included in earnings are reported as operating revenue on the Consolidated Statements of Operations. For commodity derivatives held as of September 30, 2011 and 2010, net unrealized gains (losses) included in earnings for the three-month periods ended September 30, 2011 and 2010 totaled $4 million and $5 million, respectively, and for the nine-month periods ended September 30, 2011 and 2010 totaled $5 million and $10 million, respectively.

The Company's long-term debt is carried at cost on the Consolidated Financial Statements. The fair value of the Company's long-term debt has been estimated based upon quoted market prices, where available, or at the present value of future cash flows discounted at rates consistent with comparable maturities with similar credit risks. The carrying value of the Company's variable-rate long-term debt approximates fair value because of the frequent repricing of these instruments at market rates. The following table presents the carrying value and estimated fair value of the Company's long-term debt (in millions):

	As of September 30, 2011		As of December 31, 2010	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	$ 19,916	$ 23,323	$ 19,491	$ 21,637

(6) Risk Management and Hedging Activities

The Company is exposed to the impact of market fluctuations in commodity prices, interest rates and foreign currency exchange rates. The Company is principally exposed to electricity, natural gas, coal and fuel oil commodity price risk primarily through MEHC's ownership of the Utilities as they have an obligation to serve retail customer load in their regulated service territories. MidAmerican Energy also provides nonregulated retail electricity and natural gas services in competitive markets. The Utilities' load and generating facilities represent substantial underlying commodity positions. Exposures to commodity prices consist mainly of variations in the price of fuel required to generate electricity, wholesale electricity that is purchased and sold, and natural gas supply for regulated and nonregulated retail customers. Commodity prices are subject to wide price swings as supply and demand are impacted by, among many other unpredictable items, weather, market liquidity, generating facility availability, customer usage, storage, and transmission and transportation constraints. Interest rate risk exists on variable-rate debt and future debt issuances. Additionally, the Company is exposed to foreign currency exchange rate risk from its business operations and investments in Great Britain. The Company does not engage in a material amount of proprietary trading activities.

Each of the Company's business platforms has established a risk management process that is designed to identify, assess, monitor, report, manage and mitigate each of the various types of risk involved in its business. To mitigate a portion of its commodity price risk, the Company uses commodity derivative contracts, including forwards, futures, options, swaps and other agreements, to effectively secure future supply or sell future production generally at fixed prices. The Company manages its interest rate risk by limiting its exposure to variable interest rates primarily through the issuance of fixed-rate long-term debt and by monitoring market changes in interest rates. Additionally, the Company may from time to time enter into interest rate derivative contracts, such as interest rate swaps or locks, to mitigate the Company's exposure to interest rate risk. The Company does not hedge all of its commodity price, interest rate and foreign currency exchange rate risks, thereby exposing the unhedged portion to changes in market prices.

There have been no significant changes in the Company's accounting policies related to derivatives. Refer to Note 5 for additional information on derivative contracts.

The following table, which excludes contracts that qualify for the normal purchases or normal sales exception afforded by GAAP, summarizes the fair value of the Company's derivative contracts, on a gross basis, and reconciles those amounts to the amounts presented on a net basis on the Consolidated Balance Sheets (in millions):

	Derivative Assets		Derivative Liabilities		
	Current	Noncurrent	Current	Noncurrent	Total
As of September 30, 2011					
Not designated as hedging contracts[1][2]:					
Commodity assets	$ 102	$ 12	$ 67	$ 14	$ 195
Commodity liabilities	(53)	(4)	(300)	(356)	(713)
Total	49	8	(233)	(342)	(518)
Designated as hedging contracts[1]:					
Commodity assets	3	5	3	—	11
Commodity liabilities	(3)	—	(13)	(2)	(18)
Total	—	5	(10)	(2)	(7)
Total derivatives	49	13	(243)	(344)	(525)
Cash collateral (payable) receivable	(3)	—	88	12	97
Total derivatives - net basis	$ 46	$ 13	$ (155)	$ (332)	$ (428)
As of December 31, 2010					
Not designated as hedging contracts[1][2]:					
Commodity assets	$ 204	$ 18	$ 47	$ 38	$ 307
Commodity liabilities	(64)	(6)	(269)	(533)	(872)
Total	140	12	(222)	(495)	(565)
Designated as hedging contracts[1]:					
Commodity assets	1	2	8	1	12
Commodity liabilities	(1)	(1)	(50)	(8)	(60)
Total	—	1	(42)	(7)	(48)
Total derivatives	140	13	(264)	(502)	(613)
Cash collateral (payable) receivable	(9)	—	106	44	141
Total derivatives - net basis	$ 131	$ 13	$ (158)	$ (458)	$ (472)

(1) Derivative contracts within these categories subject to master netting arrangements are presented on a net basis on the Consolidated Balance Sheets.

(2) The Company's commodity derivatives not designated as hedging contracts are generally included in regulated rates, and as of September 30, 2011 and December 31, 2010, a net regulatory asset of $517 million and $564 million, respectively, was recorded related to the net derivative liability of $518 million and $565 million, respectively.

Not Designated as Hedging Contracts

For the Company's commodity derivatives not designated as hedging contracts, the settled amount is generally included in regulated rates. Accordingly, the net unrealized gains and losses associated with interim price movements on contracts that are accounted for as derivatives and probable of inclusion in regulated rates are recorded as net regulatory assets. The following table reconciles the beginning and ending balances of the Company's net regulatory assets and summarizes the pre-tax gains and losses on commodity derivative contracts recognized in net regulatory assets, as well as amounts reclassified to earnings (in millions):

	Three-Month Periods Ended September 30,		Nine-Month Periods Ended September 30,	
	2011	2010	2011	2010
Beginning balance	$ 498	$ 479	$ 564	$ 353
Changes in fair value recognized in net regulatory assets	81	31	19	102
Net (losses) gains reclassified to operating revenue	(6)	10	2	59
Net losses reclassified to cost of sales	(56)	(37)	(68)	(31)
Ending balance	$ 517	$ 483	$ 517	$ 483

For the Company's derivatives not designated as hedging contracts and for which changes in fair value are not recorded as a net regulatory asset or liability, unrealized gains and losses are recognized on the Consolidated Statements of Operations as operating revenue for sales contracts; cost of sales and operating expense for purchase contracts and electricity, natural gas and fuel swap contracts; and interest expense for the interest rate derivative. The following table summarizes the pre-tax gains (losses) included on the Consolidated Statements of Operations associated with the Company's derivative contracts not designated as hedging contracts and not recorded as a net regulatory asset or liability (in millions):

	Three-Month Periods Ended September 30,		Nine-Month Periods Ended September 30,	
	2011	2010	2011	2010
Commodity derivatives:				
Operating revenue	$ 4	$ 10	$ 8	$ 22
Cost of sales	—	(11)	(1)	(24)
Operating expense	(4)	—	(2)	(1)
Interest rate derivative - Interest expense	—	—	—	4
Total	$ —	$ (1)	$ 5	$ 1

Designated as Hedging Contracts

The Company uses commodity derivative contracts accounted for as cash flow hedges to hedge electricity and natural gas commodity prices for delivery to nonregulated customers, spring operational sales, natural gas storage and other transactions. The Company's commodity derivative contracts designated as fair value hedges were not significant.

The following table reconciles the beginning and ending balances of the Company's accumulated other comprehensive loss (pre-tax) and summarizes pre-tax gains and losses on commodity derivative contracts designated and qualifying as cash flow hedges recognized in other comprehensive income ("OCI"), as well as amounts reclassified to earnings (in millions):

	Three-Month Periods Ended September 30,		Nine-Month Periods Ended September 30,	
	2011	2010	2011	2010
Beginning balance[(1)]	$ 15	$ 76	$ 37	$ 81
Changes in fair value recognized in OCI	(12)	36	(26)	54
Net gains (losses) reclassified to operating revenue	1	(1)	2	4
Net gains (losses) reclassified to cost of sales	3	—	(6)	(28)
Ending balance[(1)]	$ 7	$ 111	$ 7	$ 111

(1) Certain derivative contracts, principally interest rate locks, have settled and the fair value at the date of settlement remains in accumulated other comprehensive income ("AOCI") and is recognized in earnings when the forecasted transactions impact earnings.

Realized gains and losses on hedges and hedge ineffectiveness are recognized in income as operating revenue, cost of sales or operating expense depending upon the nature of the item being hedged. For the three- and nine-month periods ended September 30, 2011 and 2010, hedge ineffectiveness was insignificant. As of September 30, 2011, the Company had cash flow hedges with expiration dates extending through December 2015 and $11 million of pre-tax net unrealized losses are forecasted to be reclassified from AOCI into earnings over the next twelve months as contracts settle.

Derivative Contract Volumes

The following table summarizes the net notional amounts of outstanding commodity derivative contracts with fixed price terms that comprise the mark-to-market values as of (in millions):

	Unit of Measure	September 30, 2011	December 31, 2010
Electricity sales	Megawatt hours	(2)	(11)
Natural gas purchases	Decatherms	196	239
Fuel purchases	Gallons	6	20

Credit Risk

The Utilities extend unsecured credit to other utilities, energy marketing companies, financial institutions and other market participants in conjunction with their wholesale energy supply and marketing activities. Credit risk relates to the risk of loss that might occur as a result of nonperformance by counterparties on their contractual obligations to make or take delivery of electricity, natural gas or other commodities and to make financial settlements of these obligations. Credit risk may be concentrated to the extent that one or more groups of counterparties have similar economic, industry or other characteristics that would cause their ability to meet contractual obligations to be similarly affected by changes in market or other conditions. In addition, credit risk includes not only the risk that a counterparty may default due to circumstances relating directly to it, but also the risk that a counterparty may default due to circumstances involving other market participants that have a direct or indirect relationship with the counterparty.

The Utilities analyze the financial condition of each significant wholesale counterparty before entering into any transactions, establish limits on the amount of unsecured credit to be extended to each counterparty and evaluate the appropriateness of unsecured credit limits on an ongoing basis. To mitigate exposure to the financial risks of wholesale counterparties, the Utilities enter into netting and collateral arrangements that may include margining and cross-product netting agreements and obtain third-party guarantees, letters of credit and cash deposits. Counterparties may be assessed fees for delayed payments. If required, the Utilities exercise rights under these arrangements, including calling on the counterparty's credit support arrangement.

MidAmerican Energy also has potential indirect credit exposure to other market participants in the regional transmission organization ("RTO") markets where it actively participates, including the Midwest Independent Transmission System Operator, Inc. and the PJM Interconnection, L.L.C. In the event of a default by a RTO market participant on its market-related obligations, losses are allocated among all other market participants in proportion to each participant's share of overall market activity during the period of time the loss was incurred, diversifying MidAmerican Energy's exposure to credit losses from individual participants. Transactional activities of MidAmerican Energy and other participants in organized RTO markets are governed by credit policies specified in each respective RTO's governing tariff or related business practices. Credit policies of RTO's, which have been developed through extensive stakeholder participation, generally seek to minimize potential loss in the event of a market participant default without unnecessarily inhibiting access to the marketplace. MidAmerican Energy's share of historical losses from defaults by other RTO market participants has not been material.

Collateral and Contingent Features

In accordance with industry practice, certain wholesale derivative contracts contain provisions that require MEHC's subsidiaries, principally the Utilities, to maintain specific credit ratings from one or more of the major credit rating agencies on their unsecured debt. These derivative contracts may either specifically provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed specified rating-dependent threshold levels ("credit-risk-related contingent features") or provide the right for counterparties to demand "adequate assurance" in the event of a material adverse change in the subsidiary's creditworthiness. These rights can vary by contract and by counterparty. As of September 30, 2011, these subsidiary's credit ratings from the three recognized credit rating agencies were investment grade.

The aggregate fair value of the Company's derivative contracts in liability positions with specific credit-risk-related contingent features totaled $525 million and $603 million as of September 30, 2011 and December 31, 2010, respectively, for which the Company had posted collateral of $86 million and $136 million, respectively. If all credit-risk-related contingent features for derivative contracts in liability positions had been triggered as of September 30, 2011 and December 31, 2010, the Company would have been required to post $289 million and $261 million, respectively, of additional collateral. The Company's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation, or other factors.

(7) Investments and Restricted Cash and Investments

Investments and restricted cash and investments consists of the following (in millions):

	As of	
	September 30, 2011	**December 31, 2010**
Investments:		
BYD common stock	$ 381	$ 1,182
Rabbi trusts	281	284
Other	103	105
Total investments	765	1,571
Restricted cash and investments:		
Nuclear decommissioning trust funds	287	295
Other	81	59
Total restricted cash and investments	368	354
Total investments and restricted cash and investments	1,133	1,925
Less current portion	(65)	(44)
Noncurrent portion	$ 1,068	$ 1,881

MEHC's investment in BYD Company Limited ("BYD") common stock is accounted for as an available-for-sale security with changes in fair value recognized in AOCI. As of September 30, 2011 and December 31, 2010, the fair value of MEHC's investment in BYD common stock was $381 million and $1.182 billion, respectively, which resulted in a pre-tax unrealized gain of $149 million and $950 million as of September 30, 2011 and December 31, 2010, respectively.

The Company's restricted cash and investments as of September 30, 2011 and December 31, 2010 are primarily related to (a) funds held in trust for nuclear decommissioning and (b) debt service reserve requirements for certain projects. The debt service funds are restricted by their respective project debt agreements to be used only for the related project.

(8) Recent Debt Transactions

In conjunction with the construction of wind-powered generating facilities, MidAmerican Energy has accrued as construction work-in-progress certain amounts for which it is not contractually obligated to pay until December 2013. The amounts ultimately payable are discounted at 1.46% and recognized upon delivery of the equipment as long-term debt. The discount is amortized as interest expense over the period until payment is due using the effective interest method. As of September 30, 2011, $376 million of such debt, net of associated discount, was outstanding.

In May 2011, PacifiCorp issued $400 million of 3.85% First Mortgage Bonds due June 15, 2021. The net proceeds were used to fund capital expenditures, repay short-term debt and for general corporate purposes.

In April 2011, Northern Natural Gas issued $200 million of 4.25% Senior Notes due June 1, 2021. The net proceeds were used to partially repay its $250 million, 7.0% Senior Notes due June 1, 2011.

In January and February 2011, Northern Powergrid (Northeast) Limited issued £119 million of notes with maturity dates ranging from 2018 to 2020 at interest rates ranging from 3.901% to 4.586% under its finance contract with the European Investment Bank.

(9) Related Party Transactions

As of September 30, 2011 and December 31, 2010, Berkshire Hathaway and its affiliates held 11% mandatory redeemable preferred securities due from certain wholly-owned subsidiary trusts of MEHC of $43 million and $165 million, respectively. Interest expense on these securities totaled $3 million and $7 million for the three-month periods ended September 30, 2011 and 2010, respectively, and $12 million and $25 million for the nine-month periods ended September 30, 2011 and 2010, respectively.

Berkshire Hathaway includes the Company in its United States federal income tax return. As of September 30, 2011 and December 31, 2010, income taxes receivable from Berkshire Hathaway totaled $30 million and $396 million, respectively. For the nine-month periods ended September 30, 2011 and 2010, the Company received net cash payments for income taxes from Berkshire Hathaway totaling $670 million and $132 million, respectively.

(10) Employee Benefit Plans

Domestic Operations

Net periodic benefit cost for the domestic pension and other postretirement benefit plans included the following components (in millions):

	Three-Month Periods Ended September 30,		Nine-Month Periods Ended September 30,	
	2011	2010	2011	2010
Pension:				
Service cost	$ 6	$ 8	$ 20	$ 22
Interest cost	26	25	78	78
Expected return on plan assets	(29)	(29)	(88)	(86)
Net amortization	6	3	15	10
Net periodic benefit cost	$ 9	$ 7	$ 25	$ 24
Other postretirement:				
Service cost	$ 3	$ 2	$ 8	$ 7
Interest cost	10	10	31	31
Expected return on plan assets	(12)	(11)	(33)	(32)
Net amortization	4	5	12	11
Net periodic benefit cost	$ 5	$ 6	$ 18	$ 17

Employer contributions to the domestic pension and other postretirement benefit plans are expected to be $127 million and $28 million, respectively, during 2011. As of September 30, 2011, $123 million and $21 million of contributions had been made to the domestic pension and other postretirement benefit plans, respectively.

United Kingdom Operations

Net periodic benefit cost for the UK pension plan included the following components (in millions):

	Three-Month Periods Ended September 30,		Nine-Month Periods Ended September 30,	
	2011	2010	2011	2010
Service cost	$ 5	$ 5	$ 15	$ 12
Interest cost	24	22	70	66
Expected return on plan assets	(29)	(26)	(87)	(76)
Net amortization	9	7	27	22
Net periodic benefit cost	$ 9	$ 8	$ 25	$ 24

Employer contributions to the UK pension plan are expected to be £50 million during 2011. As of September 30, 2011, £37 million, or $60 million, of contributions had been made to the UK pension plan.

(11) Income Taxes

A reconciliation of the federal statutory income tax rate to the effective income tax rate applicable to income before income tax expense is as follows:

	Three-Month Periods Ended September 30,		Nine-Month Periods Ended September 30,	
	2011	2010	2011	2010
Federal statutory income tax rate	35%	35%	35%	35%
Federal and state income tax credits	(13)	(14)	(11)	(11)
State income tax, net of federal income tax benefit	2	4	2	3
Change in United Kingdom corporate income tax rate	(9)	(6)	(3)	(2)
Tax free gain on sale of business	—	(4)	—	(1)
Effects of ratemaking	(1)	(4)	(1)	(3)
Income tax effect of foreign income	(2)	(2)	(2)	(3)
Noncontrolling interest verdict	—	—	—	(2)
Other, net	3	1	1	(1)
Effective income tax rate	15%	10%	21%	15%

Federal and state income tax credits primarily relate to production tax credits at the Utilities. The Utilities' wind-powered generating facilities are eligible for federal renewable electricity production tax credits for 10 years from the date the facilities were placed in service.

In July 2011, the Company recognized $40 million of deferred income tax benefits upon the enactment of a reduction in the United Kingdom corporate income tax rate from 27% to 26% effective April 1, 2011, and a further reduction to 25% effective April 1, 2012. In July 2010, the Company recognized $25 million of deferred income tax benefits upon the enactment of the reduction in the United Kingdom corporate income tax rate from 28% to 27% effective April 1, 2011.

In September 2010, the Company sold its interest in CE Gas (Australia) Limited and recognized a tax free gain of $45 million.

(12) Commitments and Contingencies

Legal Matters

The Company is party to a variety of legal actions arising out of the normal course of business. Plaintiffs occasionally seek punitive or exemplary damages. The Company does not believe that such normal and routine litigation will have a material impact on its consolidated financial results.

Environmental Laws and Regulations

The Company is subject to federal, state, local and foreign laws and regulations regarding air and water quality, renewable portfolio standards, emissions performance standards, climate change, coal combustion byproduct disposal, hazardous and solid waste disposal, protected species and other environmental matters that have the potential to impact the Company's current and future operations. The Company believes it is in material compliance with all applicable laws and regulations.

Hydroelectric Relicensing

PacifiCorp's hydroelectric portfolio consists of 44 generating facilities with an aggregate facility net owned capacity of 1,145 megawatts. The FERC regulates 98% of the net capacity of this portfolio through 15 individual licenses, which have terms of 30 to 50 years. PacifiCorp expects to incur ongoing operating and maintenance expense and capital expenditures associated with the terms of its renewed hydroelectric licenses and settlement agreements, including natural resource enhancements. PacifiCorp's Klamath hydroelectric system is currently operating under annual licenses. Substantially all of PacifiCorp's remaining hydroelectric generating facilities are operating under licenses that expire between 2030 and 2058.

In February 2010, PacifiCorp, the United States Department of the Interior, the United States Department of Commerce, the State of California, the State of Oregon and various other governmental and non-governmental settlement parties signed the Klamath Hydroelectric Settlement Agreement ("KHSA"). Among other things, the KHSA provides that the United States Department of the Interior conduct scientific and engineering studies to assess whether removal of the Klamath hydroelectric system's four mainstem dams is in the public interest and will advance restoration of the Klamath Basin's salmonid fisheries. If it is determined that dam removal should proceed, dam removal is expected to commence no earlier than 2020.

Under the KHSA, PacifiCorp and its customers are protected from uncapped dam removal costs and liabilities. For dam removal to occur, federal legislation consistent with the KHSA must be enacted to provide, among other things, protection for PacifiCorp from all liabilities associated with dam removal activities. If Congress does not enact legislation, then PacifiCorp will resume relicensing at the FERC. In addition, the KHSA limits PacifiCorp's contribution to dam removal costs to no more than $200 million, of which up to $184 million would be collected from PacifiCorp's Oregon customers with the remainder to be collected from PacifiCorp's California customers. An additional $250 million for dam removal costs is expected to be raised through a California bond measure or other appropriate State of California financing mechanism. If dam removal costs exceed $200 million and if the State of California is unable to raise the additional funds necessary for dam removal costs, sufficient funds would need to be provided by an entity other than PacifiCorp in order for the KHSA and dam removal to proceed.

PacifiCorp has begun collection of surcharges from Oregon customers for their share of dam removal costs, as approved by the Oregon Public Utility Commission ("OPUC"), and is depositing the proceeds in a trust account maintained by the OPUC. PacifiCorp will begin collection of surcharges from California customers for their share of dam removal costs, as approved by the California Public Utilities Commission ("CPUC"),upon the establishment of two trust accounts.

As of September 30, 2011 and December 31, 2010, PacifiCorp's property, plant and equipment, net included $120 million and $125 million, respectively, of costs associated with the Klamath hydroelectric system's four mainstem dams and the associated relicensing and settlement costs. During 2010 and 2011, PacifiCorp received approvals from the OPUC, the CPUC and the Wyoming Public Service Commission to depreciate the Klamath hydroelectric system's four mainstem dams and the associated relicensing and settlement costs through the expected dam removal date. The depreciation rate changes were effective January 1, 2011 and will allow for full depreciation of the assets by December 2019 for those jurisdictions. PacifiCorp is seeking similar approval in Idaho and expects to seek approval in the next Washington general rate case. As part of the July 2011 Utah general rate case settlement that was approved by the UPSC in August 2011, PacifiCorp and the other parties to the settlement agreed to defer a decision regarding the acceleration of the depreciation rates for the Klamath hydroelectric system's four mainstem dams to a future rate proceeding, at which time the associated relicensing and settlement costs would be addressed.

Purchase Obligations

In May 2011, PacifiCorp issued a notice to proceed with the engineering, procurement and construction contract for the 637-MW Lake Side 2 combined-cycle combustion turbine natural gas-fired generating facility. The notice to proceed resulted in purchase obligations for the years ending December 31 of approximately $181 million in 2011, $206 million in 2012, $126 million in 2013 and $8 million in 2014.

In May 2011, MidAmerican Energy signed contracts totaling $427 million for the construction of emissions control equipment at two of its jointly owned generating facilities to address air quality requirements. These contracts resulted in purchase obligations for the years ending December 31 of approximately $143 million in 2012, $194 million in 2013 and $90 million in 2014. As a joint owner of the generating facilities, MidAmerican Energy's share is $238 million.

(13) Components of Accumulated Other Comprehensive Loss, Net

Accumulated other comprehensive loss attributable to MEHC, net consists of the following components (in millions):

	As of	
	September 30, 2011	December 31, 2010
Unrecognized amounts on retirement benefits, net of tax of $(165) and $(172)	$ (442)	$ (461)
Foreign currency translation adjustment	(298)	(297)
Unrealized gains on cash flow hedges, net of tax of $25 and $15	38	23
Unrealized gains on available-for-sale securities, net of tax of $52 and $375	74	561
Total accumulated other comprehensive loss attributable to MEHC, net	$ (628)	$ (174)

(14) Segment Information

MEHC's reportable segments were determined based on how the Company's strategic units are managed. The Company's foreign reportable segments include Northern Powergrid Holdings, whose business is principally in Great Britain, and CalEnergy Philippines, whose business is in the Philippines. Intersegment eliminations and adjustments, including the allocation of goodwill, have been made. Information related to the Company's reportable segments is shown below (in millions):

	Three-Month Periods Ended September 30,		Nine-Month Periods Ended September 30,	
	2011	2010	2011	2010
Operating revenue:				
PacifiCorp	$ 1,198	$ 1,165	$ 3,408	$ 3,323
MidAmerican Funding	866	933	2,650	2,895
Northern Natural Gas	112	116	429	423
Kern River	90	90	268	264
Northern Powergrid Holdings	237	184	727	582
CalEnergy Philippines	37	25	83	69
CalEnergy U.S.	8	9	24	25
HomeServices	285	253	764	793
Corporate/other(1)	(13)	(12)	(43)	(44)
Total operating revenue	$ 2,820	$ 2,763	$ 8,310	$ 8,330
Depreciation and amortization:				
PacifiCorp	$ 154	$ 140	$ 465	$ 422
MidAmerican Funding	79	86	248	258
Northern Natural Gas	17	16	51	48
Kern River	27	27	86	81
Northern Powergrid Holdings	42	43	125	119
CalEnergy Philippines	6	6	17	17
CalEnergy U.S.	2	2	6	6
HomeServices	3	4	9	11
Corporate/other(1)	(3)	(4)	(10)	(12)
Total depreciation and amortization	$ 327	$ 320	$ 997	$ 950
Operating income:				
PacifiCorp	$ 320	$ 284	$ 858	$ 815
MidAmerican Funding	148	148	346	364
Northern Natural Gas	28	31	174	175
Kern River	51	51	146	148
Northern Powergrid Holdings	136	136	431	348
CalEnergy Philippines	29	17	58	45
CalEnergy U.S.	5	5	9	13
HomeServices	18	3	25	20
Corporate/other(1)	(7)	(31)	(38)	(65)
Total operating income	728	644	2,009	1,863
Interest expense	(301)	(309)	(907)	(923)
Capitalized interest	13	14	31	42
Interest and dividend income	2	4	11	24
Other, net	17	33	63	89
Total income before income tax expense and equity income	$ 459	$ 386	$ 1,207	$ 1,095

	Three-Month Periods Ended September 30,		Nine-Month Periods Ended September 30,	
	2011	2010	2011	2010
Interest expense:				
PacifiCorp	$ 106	$ 101	$ 309	$ 303
MidAmerican Funding	45	48	138	144
Northern Natural Gas	13	15	43	45
Kern River	12	12	35	38
Northern Powergrid Holdings	38	37	116	109
CalEnergy Philippines	—	2	2	4
CalEnergy U.S.	3	4	11	12
Corporate/other(1)	84	90	253	268
Total interest expense	$ 301	$ 309	$ 907	$ 923

	As of	
	September 30, 2011	December 31, 2010
Total assets:		
PacifiCorp	$ 21,815	$ 21,410
MidAmerican Funding	11,903	11,134
Northern Natural Gas	2,674	2,795
Kern River	2,074	1,949
Northern Powergrid Holdings	5,680	5,512
CalEnergy Philippines	334	336
CalEnergy U.S.	586	569
HomeServices	666	649
Corporate/other(1)	670	1,314
Total assets	$ 46,402	$ 45,668

(1) The remaining differences between the segment amounts and the consolidated amounts described as "Corporate/other" relate principally to intersegment eliminations for operating revenue and, for the other items presented, to (a) corporate functions, including administrative costs, interest expense, corporate cash and investments and related interest income and (b) intersegment eliminations.

The following table shows the change in the carrying amount of goodwill by reportable segment for the nine-month period ended September 30, 2011 (in millions):

	PacifiCorp	MidAmerican Funding	Northern Natural Gas	Kern River	Northern Powergrid Holdings	CalEnergy U.S.	Home-Services	Total
Balance, December 31, 2010	$ 1,126	$ 2,102	$ 197	$ 34	$ 1,101	$ 71	$ 394	$ 5,025
Foreign currency translation	—	—	—	—	(1)	—	—	(1)
Other	—	—	(19)	—	—	—	—	(19)
Balance at September 30, 2011	$ 1,126	$ 2,102	$ 178	$ 34	$ 1,100	$ 71	$ 394	$ 5,005

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following is management's discussion and analysis of certain significant factors that have affected the consolidated financial condition and results of operations of the Company during the periods included herein. Explanations include management's best estimate of the impacts of weather, customer growth and other factors. This discussion should be read in conjunction with the Company's historical unaudited Consolidated Financial Statements and Notes to Consolidated Financial Statements in Item 1 of this Form 10-Q. The Company's actual results in the future could differ significantly from the historical results.

The Company's operations are organized and managed as eight distinct platforms: PacifiCorp, MidAmerican Funding (which primarily consists of MidAmerican Energy), Northern Natural Gas, Kern River, Northern Powergrid Holdings (which primarily consists of Northern Powergrid (Northeast) Limited and Northern Powergrid (Yorkshire) plc), CalEnergy Philippines (which owns a majority interest in the Casecnan project in the Philippines), CalEnergy U.S. (which owns interests in independent power projects in the United States), and HomeServices. Through these platforms, the Company owns and operates an electric utility company in the Western United States, an electric and natural gas utility company in the Midwestern United States, two interstate natural gas pipeline companies in the United States, two electricity distribution companies in Great Britain, a diversified portfolio of independent power projects and the second largest residential real estate brokerage firm in the United States.

Results of Operations for the Third Quarter and First Nine Months of 2011 and 2010

Overview

Net income attributable to MEHC for the three-month period ended September 30, 2011 was $412 million, an increase of $48 million, or 13%, compared to 2010. PacifiCorp's net income was $170 million for 2011, an increase of $13 million, or 8%, compared to 2010 as higher retail prices approved by regulators, the net impact of the Utah rate case settlement and higher customer load were partially offset by higher purchased power costs, higher depreciation and amortization and lower AFUDC. Net income at MidAmerican Funding was $104 million for 2011, and was relatively flat compared to 2010 as lower wholesale electric margins and a higher effective income tax rate due to the effects of ratemaking were offset by higher AFUDC related to wind-powered generation projects and lower depreciation and amortization. Net income at Kern River was $30 million for 2011, an increase of $5 million, or 20%, compared to 2010 due to higher AFUDC on the Apex Expansion project. Northern Powergrid Holdings' net income was $118 million for 2011, an increase of $6 million, or 5%, compared to 2010 due to higher distribution revenue, higher deferred income tax benefits in 2011 related to enacted changes in the United Kingdom's corporate income tax rate and $5 million due to a weaker United States dollar, partially offset by a tax free gain of $45 million recognized on the sale of CE Gas (Australia) Limited in 2010. CalEnergy Philippines' net income increased $8 million, or 73%, for 2011 compared to 2010 due to higher variable energy fees earned in 2011 from higher rainfall. Net income at HomeServices was higher by $8 million, or 160%, for 2011 compared to 2010 due to an increase in closed brokerage units, partially offset by lower average home sale prices. Net income for corporate/other increased $7 million, or 9%, for 2011 compared to 2010 due to lower interest expense.

Net income attributable to MEHC for the nine-month period ended September 30, 2011 was $979 million, an increase of $120 million, or 14%, compared to 2010. PacifiCorp's net income was $426 million for 2011, a decrease of $19 million, or 4%, compared to 2010 as higher retail prices approved by regulators, higher customer load, the net impact of the Utah rate case settlement and lower fuel costs were more than offset by lower wholesale revenue, higher purchased power costs, lower AFUDC, higher depreciation and amortization and higher operating expense. Net income at MidAmerican Funding was $217 million for 2011, a decrease of $17 million, or 7%, compared to 2010 due to lower wholesale electric margins, resulting from lower volumes and average prices, higher operating expense and higher income tax expense due to the effects of ratemaking, partially offset by higher AFUDC related to wind-powered generation projects and lower depreciation and amortization. Net income at Kern River was $80 million for 2011, an increase of $9 million, or 13%, compared to 2010 due to higher AFUDC on the Apex Expansion project. Northern Powergrid Holdings' net income was $278 million for 2011, an increase of $67 million, or 32%, compared to 2010 due to higher distribution revenue, higher deferred income tax benefits in 2011 related to enacted changes in the United Kingdom's corporate income tax rate and $13 million due to a weaker United States dollar, partially offset by a tax free gain of $45 million recognized on the sale of CE Gas (Australia) Limited in 2010. Net income increased $5 million, or 42%, at CalEnergy U.S. for 2011 compared to 2010 due to higher equity income resulting from improved results at the gas plants. HomeServices' net income was lower by $4 million, or 17%, for 2011 compared to 2010 due to a decrease in average home sale prices and closed brokerage units and lower earnings at its mortgage joint venture. The results for 2010 included an after-tax charge of $59 million related to the CE Casecnan noncontrolling interest verdict. Additionally, corporate/other's net income increased $13 million, or 7%, for 2011 compared to 2010 due to lower interest expense and higher equity income from ETT, partially offset by a dividend received in 2010 from BYD Company Limited.

Segment Results

The reportable segment financial information includes all necessary adjustments and eliminations needed to conform to the Company's significant accounting policies. The differences between the segment amounts and the consolidated amounts, described as "Corporate/other," relate principally to corporate functions, including administrative costs and intersegment eliminations.

Operating revenue and operating income for the Company's reportable segments are summarized as follows (in millions):

	Third Quarter				First Nine Months			
	2011	2010	Change		2011	2010	Change	
Operating revenue:								
PacifiCorp	$ 1,198	$ 1,165	$ 33	3%	$ 3,408	$ 3,323	$ 85	3%
MidAmerican Funding	866	933	(67)	(7)	2,650	2,895	(245)	(8)
Northern Natural Gas	112	116	(4)	(3)	429	423	6	1
Kern River	90	90	—	—	268	264	4	2
Northern Powergrid Holdings	237	184	53	29	727	582	145	25
CalEnergy Philippines	37	25	12	48	83	69	14	20
CalEnergy U.S.	8	9	(1)	(11)	24	25	(1)	(4)
HomeServices	285	253	32	13	764	793	(29)	(4)
Corporate/other	(13)	(12)	(1)	(8)	(43)	(44)	1	2
Total operating revenue	$ 2,820	$ 2,763	$ 57	2	$ 8,310	$ 8,330	$ (20)	—
Operating income:								
PacifiCorp	$ 320	$ 284	$ 36	13%	$ 858	$ 815	$ 43	5%
MidAmerican Funding	148	148	—	—	346	364	(18)	(5)
Northern Natural Gas	28	31	(3)	(10)	174	175	(1)	(1)
Kern River	51	51	—	—	146	148	(2)	(1)
Northern Powergrid Holdings	136	136	—	—	431	348	83	24
CalEnergy Philippines	29	17	12	71	58	45	13	29
CalEnergy U.S.	5	5	—	—	9	13	(4)	(31)
HomeServices	18	3	15	*	25	20	5	25
Corporate/other	(7)	(31)	24	77	(38)	(65)	27	42
Total operating income	$ 728	$ 644	$ 84	13	$ 2,009	$ 1,863	$ 146	8

* Not meaningful

PacifiCorp

Operating revenue increased $33 million for the third quarter of 2011 compared to 2010 due to higher retail revenue of $60 million, partially offset by lower wholesale and other revenue of $27 million. The increase in retail revenue was due to higher prices approved by regulators of $49 million and higher commercial customer load in Utah and Oregon. Total retail load increased 1% in the quarter. The decrease in wholesale and other revenue was due to a rate case settlement in Utah to refund to customers amounts associated with sales of RECs totaling $30 million.

Operating income increased $36 million for the third quarter of 2011 compared to 2010 due to the higher operating revenue. Lower energy costs were offset by higher depreciation and amortization of $14 million due to plant recently placed in service and higher operating expense. Energy costs decreased due to the favorable impact of the rate case settlement in Utah for the deferral of power costs totaling $60 million and lower natural gas costs of $16 million, partially offset by higher purchased power costs of $30 million and higher coal costs of $21 million due to higher unit costs. Energy supplied increased 3% for the third quarter of 2011 compared to 2010 as higher purchased power and hydroelectric generation were partially offset by lower natural gas generation. Purchased power costs increased on higher purchased power volumes of 16%, which displaced generation at PacifiCorp's higher cost natural gas-fired generating facilities.

Operating revenue increased $85 million for the first nine months of 2011 compared to 2010 due to higher retail revenue of $236 million, partially offset by lower wholesale and other revenue of $151 million. The increase in retail revenue was due to higher prices approved by regulators of $183 million and higher customer load. Customer load increased 3% due to higher commercial load in Utah and Oregon, higher industrial load in Utah and higher residential load in Oregon due to the impact of cooler weather. The decrease in wholesale and other revenue was due to a 27% decrease in average wholesale prices, a 7% decrease in wholesale volumes and the rate case settlement in Utah associated with sales of RECs totaling $30 million.

Operating income increased $43 million for the first nine months of 2011 compared to 2010 due to the higher operating revenue and lower energy costs of $30 million, partially offset by higher depreciation and amortization of $42 million and higher operating expense of $30 million due to higher plant placed in service. Additionally, operating expense increased due to higher salaries and benefit expenses and material and supplies expense in 2011. Energy costs decreased due to lower natural gas costs of $67 million, the favorable impact of the rate case settlement in Utah for the deferral of power costs totaling $60 million and net higher deferrals of net power costs in accordance with established adjustment mechanisms of $8 million, partially offset by higher coal costs of $57 million due to higher unit costs and purchased power costs of $48 million. Energy supplied increased 1% for the first nine months of 2011 compared to 2010 as higher purchased power, hydroelectric generation and wind-powered generation were largely offset by lower natural gas and coal generation. Purchased power costs increased on higher purchased power volumes of 23%, which displaced generation at PacifiCorp's higher cost natural gas-fired generating facilities, partially offset by lower average purchased power prices.

MidAmerican Funding

MidAmerican Funding's operating revenue and operating income are summarized as follows (in millions):

	Third Quarter				First Nine Months			
	2011	2010	Change		2011	2010	Change	
Operating revenue:								
Regulated electric	$ 487	$ 505	$ (18)	(4)%	$ 1,276	$ 1,361	$ (85)	(6)%
Regulated natural gas	99	110	(11)	(10)	562	625	(63)	(10)
Nonregulated and other	280	318	(38)	(12)	812	909	(97)	(11)
Total operating revenue	$ 866	$ 933	$ (67)	(7)	$ 2,650	$ 2,895	$ (245)	(8)
Operating income:								
Regulated electric	$ 133	$ 130	$ 3	2 %	$ 248	$ 266	$ (18)	(7)%
Regulated natural gas	(1)	(3)	2	67	48	43	5	12
Nonregulated and other	16	21	(5)	(24)	50	55	(5)	(9)
Total operating income	$ 148	$ 148	$ —	—	$ 346	$ 364	$ (18)	(5)

Regulated electric operating revenue decreased $18 million for the third quarter of 2011 compared to 2010 due to lower wholesale and other revenue of $23 million resulting from lower volumes of 16% and lower average prices of 3%, partially offset by higher retail revenue due to customer growth and the favorable impact of weather.

Regulated electric operating income increased $3 million for the third quarter of 2011 compared to 2010 as the lower operating revenue was more than offset by lower energy costs of $11 million and lower depreciation and amortization due to lower depreciation rates effective June 1, 2011 following the results of a depreciation study. The new rates generally reflect longer estimated useful lives and lower net salvage. The effect of this change is estimated to be $28 million annually based on depreciable plant balances at the time of the change. Energy costs decreased due to lower purchased energy and natural gas generation costs.

Regulated natural gas operating revenue decreased $11 million for the third quarter of 2011 compared to 2010 due to lower wholesale volumes of 37%, resulting in lower costs of sales. Regulated natural gas operating income increased $2 million for the third quarter of 2011 compared to 2010 due to lower operating expense.

Nonregulated and other operating revenue decreased $38 million for the third quarter of 2011 compared to 2010 due to lower electricity and natural gas volumes and prices. Nonregulated and other operating income decreased $5 million for the third quarter of 2011 compared to 2010 due to lower electric margins.

Regulated electric operating revenue decreased $85 million for the first nine months of 2011 compared to 2010. Wholesale and other revenue deceased $102 million due to lower volumes of 23% and lower average prices of 8%. Retail revenue increased $17 million due to a 2% increase in customer load as a result of increased customer growth and industrial sales.

Regulated electric operating income decreased $18 million for the first nine months of 2011 compared to 2010. The lower operating revenue and higher operating expense of $3 million were partially offset by lower energy costs of $60 million and depreciation and amortization of $10 million due to the lower depreciation rates. Energy costs decreased due to lower purchased energy, natural gas generation costs and coal generation costs. Operating expense increased due to higher maintenance costs, flood preparation costs and property taxes, partially offset by higher storm restoration costs in 2010.

Regulated natural gas operating revenue decreased $63 million for the first nine months of 2011 compared to 2010 due to lower wholesale volumes of 37% and a decrease in the average per-unit cost of gas sold, resulting in lower costs of sales. Regulated natural gas operating income increased $5 million for the first nine months of 2011 compared to 2010 due to higher volume-related gas margins on favorable weather conditions and other usage factors, partially offset by higher operating expense.

Nonregulated and other operating revenue decreased $97 million for the first nine months of 2011 compared to 2010 due to lower electricity and natural gas volumes and prices. Nonregulated and other operating income decreased $5 million for the first nine months of 2011 compared to 2010 due to lower margins.

Northern Natural Gas

Operating revenue decreased $4 million for third quarter of 2011 compared to 2010 due to lower transportation and storage revenue from lower volumes and rates, partially offset by higher sales of gas and condensate liquids totaling $5 million due to higher volumes. Operating income decreased $3 million for the third quarter of 2011 compared to 2010 due to the lower transportation and storage revenue, partially offset by higher margin on sales of gas and condensate liquids and lower operating expense due to reduced maintenance costs.

Operating revenue increased $6 million for the first nine months of 2011 compared to 2010 due to higher sales of gas and condensate liquids totaling $24 million on higher volumes, partially offset by lower transportation and storage revenue from lower rates. Operating income decreased by $1 million for the first nine months of 2011 compared to 2010 due to the lower transportation and storage revenue, partially offset by lower operating expense due to reduced maintenance costs and lower natural gas storage losses and higher margin on sales of gas and condensate liquids.

Kern River

Operating revenue and operating income were flat for the third quarter of 2011 compared to 2010 as higher revenue of $6 million from long-term contracts entered into in November 2010 related to the 2010 Expansion project were offset by lower revenue of $6 million from the narrowing of natural gas price spreads.

Operating revenue increased $4 million for the first nine months of 2011 compared to 2010 due to long-term contracts entered into in November 2010 related to the 2010 Expansion project totaling $17 million, partially offset by lower revenue from the narrowing of natural gas price spreads totaling $13 million. Operating income decreased $2 million for the first nine months of 2011 compared to 2010 due to higher depreciation and amortization, partially offset by the higher operating revenue.

Northern Powergrid Holdings

Operating revenue increased $53 million for the third quarter of 2011 compared to 2010. The increase was due to higher distribution revenue of $47 million and a weaker United States dollar totaling $9 million. Distribution revenue increased due to lower regulatory provisions totaling $30 million and higher tariff rates.

Operating income was flat for the third quarter of 2011 compared to 2010 as the higher distribution revenue and a weaker United States dollar were offset by the tax free gain of $45 million recognized on the sale of CE Gas (Australia) Limited in September 2010 and higher distribution costs.

Operating revenue increased $145 million for the first nine months of 2011 compared to 2010 due to the higher distribution revenue of $130 million and a weaker United States dollar totaling $33 million, partially offset by lower contracting revenue of $12 million and lower gas volumes at CE Gas. Distribution revenue increased due to lower regulatory provisions totaling $67 million and higher tariff rates.

Operating income increased $83 million for the first nine months of 2011 compared to 2010 due to the higher distribution revenue and a weaker United States dollar totaling $19 million, partially offset by the tax free gain of $45 million recognized on the sale of CE Gas (Australia) Limited in September 2010.

CalEnergy Philippines

Operating revenue and operating income increased $12 million for the third quarter of 2011 compared to 2010 due to higher variable energy fees earned in 2011 from higher rainfall. Operating revenue increased $14 million and operating income increased $13 million for the first nine months of 2011 compared to 2010 due to the higher variable energy fees earned.

CalEnergy U.S.

Operating income decreased $4 million for the first nine months of 2011 compared to 2010 due to scheduled maintenance at Cordova Energy Company.

HomeServices

Operating revenue increased $32 million for the third quarter of 2011 compared to 2010 due to a 23% increase in closed brokerage units, due in part to the expiration of the first-time homebuyer credit in June 2010 that accelerated closings into the second quarter of 2010, partially offset by an 8% decrease in average home sale prices. Operating income increased $15 million for the third quarter of 2011 compared to 2010 due to the higher operating revenue, net of commissions, and lower operating expense.

Operating revenue decreased $29 million for the first nine months of 2011 compared to 2010 due to a 3% decrease in average home sale prices and a 2% decrease in closed brokerage unit volumes. Operating income increased $5 million for the first nine months of 2011 compared to 2010 as the lower operating revenue, net of commissions, was more than offset by lower operating expense.

Corporate/other

Operating income increased $24 million for the third quarter and $27 million for first nine months of 2011 compared to 2010 due primarily to lower compensation expense, including changes in the fair value of the deferred compensation obligation.

Consolidated Other Income and Expense Items

Interest Expense

Interest expense is summarized as follows (in millions):

	Third Quarter				First Nine Months			
	2011	2010	Change		2011	2010	Change	
Subsidiary debt	$ 213	$ 213	$ —	—%	$ 638	$ 633	$ 5	1%
MEHC senior debt and other	81	82	(1)	(1)	246	247	(1)	—
MEHC subordinated debt - Berkshire Hathaway	3	7	(4)	(57)	12	25	(13)	(52)
MEHC subordinated debt - other	4	7	(3)	(43)	11	18	(7)	(39)
Total interest expense	$ 301	$ 309	$ (8)	(3)	$ 907	$ 923	$ (16)	(2)

Interest expense decreased $8 million for the third quarter and $16 million for the first nine months of 2011 compared to 2010 due to scheduled maturities and principal repayments, partially offset by a weaker United States dollar and the debt issuances at PacifiCorp ($400 million in May 2011), Northern Natural Gas ($200 million in April 2011) and Northern Powergrid Holdings (£151 million in July 2010 and £119 million in January and February 2011).

Capitalized Interest

Capitalized interest decreased $11 million for the first nine months of 2011 compared to 2010 due to lower construction work-in-progress balances at PacifiCorp, partially offset by higher construction work-in-progress balances at MidAmerican Energy and Kern River.

Interest and Dividend Income

Interest and dividend income decreased $13 million for the first nine months of 2011 compared to 2010 primarily due to an $11 million dividend received in 2010 from BYD Company Limited.

Other, Net

Other, net decreased $16 million for the third quarter and $26 million for the first nine months of 2011 compared to 2010 due to lower equity AFUDC and lower Rabbi Trust earnings. Equity AFUDC decreased due to lower construction work-in-progress balances at PacifiCorp, partially offset by higher construction work-in-progress balances at MidAmerican Energy and Kern River.

Income Tax Expense

Income tax expense increased $30 million for the third quarter of 2011 compared to 2010 and the effective tax rates were 15% and 10% for the third quarter of 2011 and 2010, respectively. The increase in the effective tax rate was due to a tax free gain on the sale of CE Gas (Australia) Limited in 2010 and the effects of ratemaking, partially offset by higher deferred income tax benefits in 2011 related to enacted changes in the United Kingdom's corporate income tax rate.

Income tax expense increased $90 million for the first nine months of 2011 compared to 2010 and the effective tax rates were 21% and 15% for the first nine months of 2011 and 2010, respectively. The increase in the effective tax rate was due to the effects of ratemaking, income tax benefits related to the noncontrolling interest verdict and a tax free gain on the sale of CE Gas (Australia) Limited in 2010, partially offset by higher deferred income tax benefits in 2011 related to enacted changes in the United Kingdom's corporate income tax rate.

In July 2011, the Company recognized $40 million of deferred income tax benefits upon the enactment of a reduction in the United Kingdom corporate income tax rate from 27% to 26% effective April 1, 2011, and a further reduction to 25% effective April 1, 2012. In July 2010, the Company recognized $25 million of deferred income tax benefits upon the enactment of the reduction in the United Kingdom corporate income tax rate from 28% to 27% effective April 1, 2011.

Equity Income

Equity income increased $4 million for the third quarter and $13 million for the first nine months of 2011 compared to 2010. Equity income was higher due to continued investment at ETT and higher earnings at CE Generation due to improved results at the gas plants, partially offset by lower earnings at HomeServices' mortgage joint venture due to lower refinancing activity and higher compliance costs.

Net Income Attributable to Noncontrolling Interests

Net income attributable to noncontrolling interests decreased $85 million for the first nine months of 2011 compared to 2010 due to the 2010 pre-tax charge related to the CE Casecnan noncontrolling interest verdict.

Liquidity and Capital Resources

Each of MEHC's direct and indirect subsidiaries is organized as a legal entity separate and apart from MEHC and its other subsidiaries. Pursuant to separate financing agreements, substantially all or most of the properties of each of MEHC's subsidiaries (except MidAmerican Energy, Northern Natural Gas, Northern Powergrid Holdings and CE Casecnan) are pledged or encumbered to support or otherwise provide the security for the related subsidiary debt. It should not be assumed that the assets of any subsidiary will be available to satisfy MEHC's obligations or the obligations of its other subsidiaries. However, unrestricted cash or other assets that are available for distribution may, subject to applicable law, regulatory commitments and the terms of financing and ring-fencing arrangements for such parties, be advanced, loaned, paid as dividends or otherwise distributed or contributed to MEHC or affiliates thereof.

As of September 30, 2011, the Company's total net liquidity was $5.216 billion. The components of total net liquidity are as follows (in millions):

	MEHC	PacifiCorp	MidAmerican Funding	Northern Powergrid Holdings	Other	Total[(1)]
Cash and cash equivalents	$ 133	$ 151	$ 379	$ 60	$ 183	$ 906
Credit facilities	552	1,355	654	234	50	2,845
Less:						
Short-term debt	—	—	—	—	—	—
Tax-exempt bond support and letters of credit	(36)	(304)	(195)	—	—	(535)
Net credit facilities	516	1,051	459	234	50	2,310
Net liquidity before Berkshire Equity Commitment	649	$ 1,202	$ 838	$ 294	$ 233	3,216
Berkshire Equity Commitment[(2)]	2,000					2,000
Total net liquidity	$ 2,649					$ 5,216
Unsecured revolving credit facilities:						
Maturity date[(3)]	2013	2012, 2013	2012, 2013	2013	2013	
Largest single bank commitment as a % of total revolving credit facilities[(4)]	18%	16%	23%	33%	100%	

(1) The above table does not include unused revolving credit facilities and letters of credit for investments that are accounted for under the equity method.

(2) MEHC has an Equity Commitment Agreement with Berkshire Hathaway (the "Berkshire Equity Commitment") pursuant to which Berkshire Hathaway has agreed to purchase up to $2.0 billion of MEHC's common equity upon any requests authorized from time to time by MEHC's Board of Directors. The proceeds of any such equity contribution shall only be used for the purpose of (a) paying when due MEHC's debt obligations and (b) funding the general corporate purposes and capital requirements of MEHC's regulated subsidiaries. The Berkshire Equity Commitment expires on February 28, 2014.

(3) For further discussion regarding the Company's credit facilities, refer to Note 9 of Notes to Consolidated Financial Statements in Item 8 of the Company's Annual Report on Form 10-K for the year ended December 31, 2010.

(4) An inability of financial institutions to honor their commitments could adversely affect the Company's short-term liquidity and ability to meet long-term commitments.

Operating Activities

Net cash flows from operating activities for the nine-month periods ended September 30, 2011 and 2010 were $2.717 billion and $2.080 billion, respectively. The increase was primarily due to higher income tax receipts of $525 million mainly attributable to bonus depreciation, benefits from changes in collateral posted for derivative contracts and a Kern River customer rate refund in 2010, partially offset by changes in working capital.

In September 2010, the President signed the Small Business Jobs Act into law, extending retroactively to January 1, 2010 the 50% bonus depreciation for qualifying property purchased and placed in service in 2010. In December 2010, the President signed the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 into law, which provided for 100% bonus depreciation for qualifying property purchased and placed in service after September 8, 2010 and prior to January 1, 2012, and 50% bonus depreciation for qualifying property purchased and placed in service after December 31, 2011 and prior to January 1, 2013. As a result of the new laws, the Company's cash flows from operations are expected to benefit in 2011 and 2012 due to bonus depreciation on qualifying assets placed in service.

Investing Activities

Net cash flows from investing activities for the nine-month periods ended September 30, 2011 and 2010 were $(1.993) billion and $(1.797) billion, respectively. The change was primarily due to proceeds received from the sale of certain Australian hydrocarbon exploration and development assets during the second quarter of 2010 totaling $78 million, net proceeds received from the sale of CE Gas (Australia) Limited during the third quarter of 2010 totaling $59 million and higher capital expenditures of $50 million.

Capital Expenditures

Capital expenditures incurred by reportable segment for the nine-month periods ended September 30 are summarized as follows (in millions):

	2011	2010
Capital expenditures[(1)]:		
PacifiCorp	$ 1,078	$ 1,196
MidAmerican Funding	779	175
Northern Natural Gas	58	88
Kern River	178	85
Northern Powergrid Holdings	237	268
Other	9	4
Total capital expenditures	$ 2,339	$ 1,816

(1) Includes amounts for changes in expenditures accrued but not yet paid and excludes amounts for non-cash equity AFUDC.

The Company's capital expenditures incurred relate primarily to the Utilities, which consisted mainly of the following for the nine-month periods ended September 30:

2011:

- The construction of 596 MW of wind-powered generating facilities totaling $558 million, including $376 million of costs for which payments are due in December 2013. MidAmerican Energy placed in service 154 MW during the third quarter of 2011 and the remaining 442 MW is expected to be placed in service during the fourth quarter of 2011.
- Emissions control equipment on existing generating facilities totaling $170 million for installation or upgrade of sulfur dioxide scrubbers, low nitrogen oxide burners and particulate matter control systems.
- Transmission system investments totaling $167 million, including permitting and right-of-way costs for the 100-mile high-voltage transmission line being built between the Mona substation in central Utah and the Oquirrh substation in the Salt Lake Valley. A 65-mile segment of the Mona to Oquirrh transmission project will be a single-circuit 500-kV transmission line, while the remaining 35-mile segment will be a double-circuit 345-kV transmission line. The transmission line is expected to be placed in service in 2013.
- The development and construction of the Lake Side 2 637-MW combined-cycle combustion turbine natural gas-fired generating facility ("Lake Side 2") totaling $123 million, which is expected to be placed in service in 2014.
- Distribution, generation, mining and other infrastructure needed to serve existing and expected demand totaling $839 million.

2010:

- Emissions control equipment totaling $256 million.
- Transmission system investments totaling $251 million, including construction costs for the Populus to Terminal segment of the Energy Gateway Transmission Expansion Program, which was placed in service in 2010.
- The construction of wind-powered generating facilities totaling $147 million, substantially for the 111-MW Dunlap Ranch wind project that was placed in service in October 2010.
- Distribution, generation, mining and other infrastructure needed to serve existing and expected demand totaling $717 million.

Additionally, capital expenditures for the nine-month periods ended September 30, 2011 and 2010 include costs related to Kern River's expansion projects totaling $162 million and $66 million, respectively. In October 2011, Kern River placed its Apex Expansion project in service, which increased its design capacity by 266 million cubic feet per day. The remaining amounts are for ongoing investments in distribution and other infrastructure needed at the other platforms to serve existing and expected demand.

Financing Activities

Net cash flows from financing activities for the nine-month period ended September 30, 2011 were $(289) million. Uses of cash totaled $1.079 billion and consisted mainly of $601 million for repayments of subsidiary debt, net repayments of short-term debt totaling $320 million and repayments of MEHC subordinated debt totaling $122 million. Sources of cash totaled $790 million and consisted of proceeds from subsidiary debt, including the following:

- In May 2011, PacifiCorp issued $400 million of 3.85% First Mortgage Bonds due June 15, 2021. The net proceeds were used to fund capital expenditures, repay short-term debt and for general corporate purposes.
- In April 2011, Northern Natural Gas issued $200 million of 4.25% Senior Notes due June 1, 2021. The net proceeds were used to partially repay its $250 million, 7.0% Senior Notes due June 1, 2011.
- In January and February 2011, Northern Powergrid (Northeast) Limited issued £119 million of notes with maturity dates ranging from 2018 to 2020 at interest rates ranging from 3.901% to 4.586% under its finance contract with the European Investment Bank.

Net cash flows from financing activities for the nine-month period ended September 30, 2010 were $(190) million. Uses of cash totaled $476 million and consisted mainly of repayments of MEHC subordinated debt totaling $259 million, repayments of subsidiary debt totaling $142 million, and net purchases of common stock totaling $56 million. Sources of cash totaled $286 million and consisted of proceeds from subsidiary debt totaling $231 million and net proceeds from short-term debt totaling $55 million.

In conjunction with the construction of wind-powered generating facilities, MidAmerican Energy has accrued as construction work-in-progress certain amounts for which it is not contractually obligated to pay until December 2013. The amounts ultimately payable are discounted at 1.46% and recognized upon delivery of the equipment as long-term debt. The discount is amortized as interest expense over the period until payment is due using the effective interest method. As of September 30, 2011, $376 million of such debt, net of associated discount, was outstanding.

Future Uses of Cash

The Company has available a variety of sources of liquidity and capital resources, both internal and external, including net cash flows from operating activities, public and private debt offerings, the issuance of commercial paper, the use of unsecured revolving credit facilities, the issuance of equity and other sources. These sources are expected to provide funds required for current operations, capital expenditures, acquisitions, investments, debt retirements and other capital requirements. The availability and terms under which each subsidiary has access to external financing depends on a variety of factors, including its credit ratings, investors' judgment of risk and conditions in the overall capital market, including the condition of the utility industry in general. Additionally, MEHC has the Berkshire Equity Commitment pursuant to which Berkshire Hathaway has agreed to purchase up to $2.0 billion of MEHC's common equity upon any requests authorized from time to time by MEHC's Board of Directors. The Berkshire Equity Commitment expires on February 28, 2014 and can be used for the purpose of (a) paying when due MEHC's debt obligations and (b) funding the general corporate purposes and capital requirements of MEHC's regulated subsidiaries. Berkshire Hathaway will have up to 180 days to fund any such request in increments of at least $250 million pursuant to one or more drawings authorized by MEHC's Board of Directors. The funding of any such drawing will be made by means of a cash equity contribution to MEHC in exchange for additional shares of MEHC's common stock.

Capital Expenditures

The Company has significant future capital requirements. Capital expenditure needs are reviewed regularly by management and may change significantly as a result of these reviews, which may consider, among other factors, changes in rules and regulations, including environmental and nuclear; outcomes of regulatory cases; changes in income tax laws; general business conditions; load projections; system reliability standards; the cost and efficiency of construction labor, equipment and materials; and the cost and availability of capital. Expenditures for compliance-related items, such as pollution-control technologies, replacement generation, nuclear decommissioning, hydroelectric relicensing, hydroelectric decommissioning and associated operating costs are generally incorporated into MEHC's energy subsidiaries' regulated retail rates.

Forecasted capital expenditures, which include amounts for expenditures accrued but not yet paid and exclude amounts for non-cash equity AFUDC, are approximately $3.7 billion for 2011, and include the following:

- $1.015 billion for wind-powered generation, including approximately $650 million of payments due in December 2013 on a 596-MW project. MidAmerican Energy placed in service 154 MW during the third quarter of 2011 and the remaining 442 MW is expected to be placed in service during the fourth quarter of 2011. MidAmerican Energy continues to evaluate additional cost-effective wind-powered generation and has authorization from the IUB, pursuant to current ratemaking principles, to construct up to 405 MW of additional wind-powered generation to be placed in service by December 31, 2012.
- $234 million for transmission system investments, including $169 million for the Energy Gateway Transmission Expansion Program, which includes permitting, right-of-way and initial construction costs for the Mona to Oquirrh transmission line.
- $246 million for emissions control equipment at the Utilities, which includes equipment to meet air and water quality and visibility permit requirements, including the reduction of sulfur dioxide, nitrogen oxides and particulate matter emissions.
- $230 million for other generation development projects, primarily for development and construction of Lake Side 2, which is expected to be placed in service in 2014.
- $188 million at Kern River primarily for the Apex Expansion project, which was placed in service in October 2011.
- Remaining amounts are for ongoing investments in distribution, generation, mining and other infrastructure needed to serve existing and expected demand.

MidAmerican Energy has begun preliminary investigation into possible development of a nuclear generation facility. In support of such investigatory activities, Iowa law authorizes recovery of approximately $15 million over three years beginning in October 2010 from MidAmerican Energy's Iowa customers for the cost of this effort, subject to the review of the IUB. MidAmerican Energy has not entered into any material commitments with regard to nuclear facility development.

MidAmerican Energy is currently evaluating a number of transmission development projects within the MISO footprint in Iowa and Illinois. MidAmerican Energy has submitted to the MISO for its consideration several Multi-Value Projects ("MVP") totaling approximately $600 million in capital costs, for which it expects feedback by the end of 2011. If such projects are approved by the MISO, the bulk of the capital expenditures would occur in the 2015-2018 time frame.

Separately, in July 2011, the FERC issued Order No. 1000, which addresses transmission planning and cost allocation issues. Among other things, Order No. 1000 removes the federal right of first refusal for certain new transmission investments. MidAmerican Energy continues to evaluate Order No. 1000 to determine its impact on the proposed MVP. While MidAmerican Energy may be the developer of these projects, a significant portion of the revenue requirement associated with the investments would be shared with other MISO participants based on the MISO's cost allocation methodology. Additionally, other MISO participants have similar proposed transmission projects that are in various stages of consideration by the MISO, for which a portion of the revenue requirement would be allocated to MidAmerican Energy based on the MISO's cost allocation process. MidAmerican Energy cannot predict which, if any, of these projects will be approved and proceed with development.

Equity Investments

ETT, a company owned equally by subsidiaries of American Electric Power Company, Inc. and MEHC, owns and operates electric transmission assets in the ERCOT. In order to fund ETT's ongoing transmission investment, MEHC expects to make equity contributions to ETT during 2011 of $91 million.

Contractual Obligations

As of September 30, 2011, there have been no material changes outside the normal course of business in contractual obligations from the information provided in Item 7 of the Company's Annual Report on Form 10-K for the year ended December 31, 2010 other than the 2011 debt issuances previously discussed and the additional purchase obligations disclosed in Note 12 of Notes to Consolidated Financial Statements. Additionally, refer to the "Capital Expenditures" discussion included in "Liquidity and Capital Resources."

Regulatory Matters

MEHC's regulated subsidiaries are subject to comprehensive regulation. In addition to the discussion contained herein regarding updates to regulatory matters based upon material changes that occurred subsequent to those disclosed in Item 7 of the Company's Annual Report on Form 10-K for the year ended December 31, 2010, refer to Note 4 of Notes to Consolidated Financial Statements in Item 1 of this Form 10-Q for additional regulatory matter updates.

PacifiCorp

Utah

In March 2009, PacifiCorp filed for an ECAM with the UPSC. The filing recommended that the UPSC adopt the mechanism to recover the difference between base net power costs set in the next Utah general rate case and actual net power costs. In February 2010, PacifiCorp filed an application with the UPSC seeking approval to defer the difference between the net power costs allowed by the UPSC's final order in PacifiCorp's 2009 general rate case and the actual net power costs incurred. Also in February 2010, the Utah Association of Energy Users filed a motion with the UPSC requesting deferral of incremental REC revenue in excess of the REC value utilized in Utah rates established by the 2009 general rate case. In July 2010, the UPSC issued an order approving a stipulation that would establish deferred accounts for both net power costs and REC revenues in excess of the levels currently included in rates, subject to the UPSC's final determination of the ratemaking treatment of the deferrals. In December 2010, the UPSC approved a separate stipulation that provided a $3 million monthly credit to customers effective January 1, 2011 to be applied toward the UPSC's final decision. In March 2011, the UPSC issued its final order approving the use of an EBA in Utah to begin at the conclusion of the general rate case described below. Under the EBA, which has been established as a four year pilot program, 70% of any difference between actual net power costs incurred and the amount of net power costs recovered through base rates, subject to certain other adjustments, are deferred during the calendar year. PacifiCorp must then file by March 15 of the following year to initiate collection or refund of the deferred balance. The UPSC did not address in its EBA order the ratemaking treatment of the deferred accounts for net power costs and REC revenues in excess of the levels included in rates since the 2009 general rate case. In April 2011, PacifiCorp filed a petition with the UPSC for clarification and reconsideration of certain aspects of the EBA order. In May 2011, the UPSC granted PacifiCorp's petition for reconsideration of the UPSC's decision to exclude financial swaps from the EBA. The UPSC denied reconsideration of the 70% sharing of incremental net power costs not in base rates and clarified that the final order does not preclude future consideration of balancing account treatment for REC sales. These issues are included in the settlement described in the following paragraph.

In January 2011, PacifiCorp filed a general rate case with the UPSC requesting a rate increase of $232 million, or an average price increase of 14%. In June 2011, PacifiCorp filed its rebuttal testimony with the UPSC reducing the requested rate increase to $188 million, or an average price increase of 11%. In July 2011, PacifiCorp filed a settlement with the UPSC, which was approved by the UPSC in August 2011 and resulted in a $117 million rate increase, or an average price increase of 7% effective September 21, 2011. The settlement resolves all major dockets outstanding before the UPSC. Under the terms of the settlement, financial swaps are included in the EBA and a collaborative process with Utah stakeholders may result in future modifications to PacifiCorp's risk management and hedging policies. The settlement also concludes the ratemaking treatment of deferred accounts for net power costs and estimated sales of RECs in excess of the levels included in rates since the 2009 general rate case. The settlement provides for $60 million of net power costs in excess of amounts included in base rates to be recovered from Utah customers over a three-year period beginning June 1, 2012, without carrying charges. The settlement also provides for a $33 million credit to customers related to sales of RECs that substantially occurred in prior years and that will be credited to Utah customers over a period of approximately nine months beginning September 21, 2011, plus carrying charges. The settlement also establishes a balancing account for prospective REC sales. The settlement stipulation defers decisions regarding the ratemaking treatment associated with the Klamath hydroelectric system's four mainstem dams and relicensing and settlement costs as described in Note 12 to Notes to Consolidated Financial Statements.

Oregon

In March 2011, PacifiCorp made its initial filing for the annual TAM with the OPUC for an annual increase of $62 million to recover the anticipated net power costs forecasted for calendar year 2012. In July 2011, PacifiCorp filed updated net power costs, reflecting an increase in the overall request to $63 million. In August 2011, PacifiCorp filed its surrebuttal testimony in the TAM proceeding decreasing the overall request to $59 million due to a reduction in forecasted net power costs. In September 2011, PacifiCorp reached a settlement with several parties, including the OPUC staff, to reduce the requested increase to $51 million, or an average price increase of 4%. The OPUC is expected to issue a decision on the stipulation in the fourth quarter of 2011. The new rates are subject to updates through November 2011 and will be effective January 1, 2012.

In October 2010, PacifiCorp filed its 2009 tax report under Oregon Senate Bill 408 ("SB 408"). In January 2011, PacifiCorp entered into a stipulation with the OPUC staff and the Citizens' Utility Board of Oregon, whereby PacifiCorp, the OPUC staff and the Citizens' Utility Board of Oregon agreed to a surcharge of $13 million, plus interest. In April 2011, the OPUC issued an order adopting the stipulation without significant modification. The $13 million, plus interest, was recorded in earnings in the second quarter of 2011 and is being collected over a one-year period that began in June 2011.

In May 2011, Oregon Senate Bill 967 ("SB 967") was enacted into law. SB 967 immediately repealed and replaced SB 408, and as a result, PacifiCorp will no longer be required to file tax reports under SB 408. Among other matters, SB 967 directs the OPUC to consider the income tax component of rates when conducting ratemaking proceedings. The enactment of SB 967 did not impact PacifiCorp's consolidated financial results.

Wyoming

In April 2010, PacifiCorp filed an application with the WPSC requesting approval of a new ECAM to replace the existing PCAM. The PCAM concluded with the final deferral of net power costs in November 2010 and collection through March 2012. In February 2011, the WPSC issued an order approving an ECAM effective December 1, 2010, under which 70% of any difference between actual net power costs incurred and the amount of net power costs recovered through base rates, subject to certain other adjustments, are deferred as incurred during the calendar year. PacifiCorp must then file by March 15 of the following year to initiate collection or refund of the deferred balance beginning June 1.

In November 2010, PacifiCorp filed a general rate case with the WPSC requesting a rate increase of $98 million, or an average price increase of 17%. In May 2011, PacifiCorp filed its rebuttal testimony with the WPSC reducing the requested rate increase to $80 million. In June 2011, the WPSC approved a multi-party stipulation resulting in an annual rate increase of $62 million, or an average price increase of 11%. The stipulation also established a surcredit and a balancing account to pass on to or collect from customers any difference between the amount of the REC sales established in the surcredit and actual REC sales. The surcredit will be established annually based on PacifiCorp's forecasted REC sales, and the difference between the surcredit and actual REC sales will be tracked in the balancing account. For 2011, the surcredit was set at $17 million, or a 3% reduction. The rates were effective September 22, 2011.

In February 2011, PacifiCorp filed its final PCAM application with the WPSC requesting recovery of $16 million in deferred net power costs over the 12-month period ending March 31, 2012. PacifiCorp requested and received approval from the WPSC to implement an $11 million interim rate increase over the $5 million reflected in the tariff to be effective from April 1, 2011 until the WPSC issues a final order. In September 2011, PacifiCorp reached an agreement with intervening parties and filed a stipulation with the WPSC to recover $14 million in deferred net power costs. In October 2011, the WPSC approved the stipulation with an effective date of November 1, 2011.

Washington

In May 2010, PacifiCorp filed a general rate case with the WUTC requesting an annual increase of $57 million, or an average price increase of 21%. In November 2010, the requested annual increase was reduced to $49 million, or an average price increase of 18%. In March 2011, the WUTC issued a final order and clarification letter approving an annual increase of $33 million, or an average price increase of 12%, reduced in the first year by a customer bill credit of $5 million, or 2%, related to the sale of RECs expected during the twelve-month period ended March 31, 2012. The new rates were effective in April 2011. In April 2011, PacifiCorp filed a petition for reconsideration requesting the WUTC reconsider various items on the final order, including income tax and net power cost issues and the WUTC's conclusions with respect to rate of return. The WUTC staff also filed a petition for reconsideration. In May 2011, the WUTC denied the petitions for reconsideration filed by PacifiCorp and the WUTC staff. In May 2011, in accordance with the March 2011 order, PacifiCorp submitted additional information to the WUTC regarding PacifiCorp's proceeds from sales of RECs for the period January 1, 2009 forward and a detailed proposal for a tracking mechanism for proceeds of RECs. In July 2011, the WUTC issued an order requiring additional testimony regarding the ratemaking treatment of historical Washington-allocated proceeds from sales of RECs and the tracking mechanism. Initial and reply briefs from all parties are due in November 2011.

In July 2011, PacifiCorp filed a general rate case with the WUTC requesting an annual increase of $13 million, or an average price increase of 4%, with an effective date no later than June 1, 2012.

Idaho

In May 2010, PacifiCorp filed a general rate case with the IPUC requesting an annual increase of $28 million, or an average price increase of 14%. In November 2010, the requested annual increase was reduced to $25 million, or an average price increase of 12%. In December 2010, the IPUC issued an interim order approving an annual increase of $14 million, or an average price increase of 7% with an effective date of December 28, 2010. In February 2011, the IPUC issued its final order with no revisions to the December 2010 increase. In March 2011, PacifiCorp petitioned the IPUC seeking reconsideration or rehearing on certain aspects of the order, including the IPUC's conclusion that 27% of PacifiCorp's Populus to Terminal transmission line investment is not currently used and useful and should be carried as plant held for future use. The Idaho-allocated share of 27% of the investment is approximately $13 million. In April 2011, the IPUC issued an order, accepting in part and rejecting in part, PacifiCorp's motion for reconsideration, resulting in no significant changes to the IPUC's initial order. In May 2011, PacifiCorp filed an appeal of the Populus to Terminal decision to the Idaho Supreme Court requesting a determination on the legality of the IPUC's decision to exclude 27% of the Populus to Terminal line as a result of its conclusion that the line is not fully used and useful. As a result of the settlement discussed below, PacifiCorp has joined in a motion filed with the Idaho Supreme Court in October 2011, to stay the procedural schedule associated with the appeal until January 30, 2012. Should the Idaho Supreme Court grant the motion, it will allow time for the IPUC to issue an order approving the treatment of the Populus to Terminal investment set forth in the settlement of the May 2011 general rate case described below.

In May 2011, PacifiCorp filed a general rate case with the IPUC requesting an annual increase of $33 million, or an average price increase of 15%. In October 2011, a settlement was reached with the majority of parties in the case that, if approved by the IPUC, will result in a two-year agreement to increase rates by $17 million each year effective January 1, 2012 and January 1, 2013, representing an average price increase of 8% and 7%, respectively. If approved, the settlement will also resolve the dispute over the 27% of PacifiCorp's Populus to Terminal investment and recommends that the IPUC provide recovery of PacifiCorp's investment beginning on or after January 1, 2014. Hearings in the general rate case are scheduled for December 2011.

In February 2011, PacifiCorp filed an ECAM application with the IPUC requesting recovery of $13 million in deferred net power costs. In March 2011, the IPUC issued an order approving recovery of $10 million beginning April 1, 2011 and the remaining $3 million beginning in 2012.

MidAmerican Energy

On March 11, 2011, a massive earthquake and associated tsunami struck the northeast coast of Japan that resulted in severe damage to the Fukushima Daiichi nuclear generating facilities in that country. These events have had a significant impact on the Japanese economy and have elevated public concerns surrounding the safety of nuclear generation. While the situation in Japan is not expected to have a direct material impact on MidAmerican Energy's operations, the NRC has launched a review of the Fukushima Daiichi accident to apply possible lessons learned to the United States nuclear industry. The results of this NRC review could potentially impact MidAmerican Energy's interest in Quad Cities Generating Station Units 1 and 2 ("Quad Cities Station"). To date, no specific findings or orders pertinent to Quad Cities Station have been communicated to either Exelon Generation Company, LLC, the operator of Quad Cities Station, or MidAmerican Energy. The impact of the NRC's review cannot be predicted but could result in higher operating expense, higher capital costs or extended outages at Quad Cities Station.

Environmental Laws and Regulations

The Company is subject to federal, state, local and foreign laws and regulations regarding air and water quality, RPS, emissions performance standards, climate change, coal combustion byproduct disposal, hazardous and solid waste disposal, protected species and other environmental matters that have the potential to impact the Company's current and future operations. In addition to imposing continuing compliance obligations, these laws and regulations provide authority to levy substantial penalties for noncompliance including fines, injunctive relief and other sanctions. These laws and regulations are administered by the EPA and various other state, local and international agencies. All such laws and regulations are subject to a range of interpretation, which may ultimately be resolved by the courts. Environmental laws and regulations continue to evolve, and the Company is unable to predict the impact of the changing laws and regulations on its operations and consolidated financial results. The Company believes it is in material compliance with all applicable laws and regulations. Refer to "Future Uses of Cash" for discussion of the Company's forecasted environmental-related capital expenditures and Note 12 of Notes to Consolidated Financial Statements in Item 1 of this Form 10-Q for additional information regarding certain environmental laws and regulations affecting the Company. The discussion below contains material developments since those disclosed in Item 7 of the Company's Annual Report on Form 10-K for the year ended December 31, 2010.

Clean Air Standards

Clean Air Mercury Rule/Hazardous Air Pollutant Maximum Achievable Control Technology Standards

In March 2011, the EPA proposed a new rule that will require coal-fired generating facilities to reduce mercury emissions and other hazardous air pollutants through the establishment of a "Maximum Achievable Control Technology" standard rather than a cap-and-trade system. The public comment period closed in August 2011, and the final rule is expected to be issued in December 2011. The proposed rule requires that new and existing coal-fired facilities achieve emission standards for mercury, acid gases and other non-mercury hazardous air pollutants. Existing sources are required to comply with the new standards within three years after the final rule is promulgated, with individual sources granted an additional year to complete installation of controls if approved by the permitting authority. Until the rule is final, the Company cannot fully determine the costs to comply with the requirements; however, the Company believes that its emission reduction projects completed to date or currently permitted or planned for installation, including scrubbers, baghouses and electrostatic precipitators are consistent with the EPA's proposed rules and will support the Company's ability to comply with the proposal's standards for acid gases and non-mercury metallic hazardous air pollutants. The Company anticipates having to take additional actions to reduce mercury emissions and otherwise comply with the proposal's standards. Incremental costs to install and maintain mercury emissions control equipment and additional emissions monitoring equipment at each of the Company's coal-fired generating facilities will increase the cost of providing service to customers.

Regional Haze

The EPA has initiated a regional haze program intended to improve visibility in designated federally protected areas ("Class I areas"). Some of PacifiCorp's and MidAmerican Energy's generating facilities meet the threshold applicability criteria to be eligible units under the Clean Air Visibility Rules. In accordance with the federal requirements, states were required to submit SIPs by December 2007 to demonstrate reasonable progress towards achieving natural visibility conditions in Class I areas by requiring emissions controls, known as best available retrofit technology, on sources constructed between 1962 and 1977 with emissions that are anticipated to cause or contribute to impairment of visibility. Utah submitted its SIP and suggested that the emissions reduction projects planned by PacifiCorp are sufficient to meet its initial emissions reduction requirements. Utah approved amendments to its SIP submittal in April 2011, and those amendments, along with its previous SIP submittal, await approval or further direction from the EPA. Wyoming submitted its regional haze SIP to the EPA in January 2011. PacifiCorp believes that its planned emissions reduction projects will satisfy the regional haze requirements in Utah and Wyoming. It is possible that additional controls may be required after the respective SIPs have been considered by the EPA or that the timing of installation of planned controls could change. In October 2011, the EPA issued a Clean Air Act Section 114 request for information seeking analyses relating to best available retrofit technology at PacifiCorp's Hunter and Huntington generating facilities in Utah. The request is currently under review.

New Source Review

In October 2011, MidAmerican Energy received a request from the EPA Region VII pursuant to Section 114 of the Clean Air Act for information on its coal-fired generating units to supplement requests made by the EPA Region VII in 2002 and 2003. MidAmerican Energy responded to the original requests in 2003 and is in the process of gathering information responsive to the EPA's recent request.

Cross-State Air Pollution Rule

In July 2011, the EPA issued a final rule, the CSAPR, to address interstate transport of sulfur dioxide and nitrogen oxides emissions in 27 eastern and Midwestern states, including Iowa, where MidAmerican Energy operates generating facilities, and Texas, Illinois and New York, where CalEnergy U.S. operates natural gas-fired generating facilities. The CSAPR originated as the Clean Air Interstate Rule, which was vacated by the United States Court of Appeals for the District of Columbia Circuit ("D.C. Circuit"). In response to the D.C. Circuit's vacatur, the EPA issued the proposed Clean Air Transport Rule in July 2010, which has been renamed the CSAPR. Upon full implementation in 2014, the CSAPR will reduce sulfur dioxide emissions by 73% and nitrogen oxides emissions by 54% at electric generating plants as compared to 2005 levels. In addition to issuing the final rule, the EPA issued a supplemental notice of proposed rulemaking seeking comment on inclusion of Iowa and five other states in the ozone season nitrogen oxides emissions reduction requirements. MidAmerican Energy submitted comments on the supplemental proposal in August 2011. Based on the final allocation of sulfur dioxide and nitrogen oxides allowances, the Company believes its' completed and planned emissions reduction projects will be sufficient to ensure compliance with the new regulations beginning January 1, 2012 and 2014. None of PacifiCorp's generating facilities are located in states included in the CSAPR and therefore, are not impacted by the rule.

Climate Change

GHG Tailoring Rule

Effective January 2, 2011, power plants, among other facilities, were required to comply with the first phase of the GHG Tailoring Rule, which provides that any source that already has a Title V operating permit is required to have GHG provisions added to its permits upon renewal. In addition, the GHG Tailoring Rule provides that if projects at existing major sources result in an increase in emissions of GHG of at least 75,000 tons per year, such projects could trigger permitting requirements and the application of best available control technology to address GHG emissions. The second phase of the GHG Tailoring Rule took effect July 1, 2011 and broadened the scope of the sources that are required to obtain federal permits to limit GHGs to any new or modified sources that emit more than 100,000 tons per year of GHG, regardless of whether a major source air permit is required for any other pollutant regulated under the Clean Air Act.

New major sources are also required to undergo permitting and install the best available control technology if their GHG emissions exceed the applicable threshold. Several legal challenges have been filed to the EPA's final GHG Tailoring Rule in the D.C. Circuit. The EPA issued GHG best available control technology guidance documents in an effort to provide permitting authorities guidance on how to conduct a best available control technology review for GHG. Permitting authorities are beginning to implement the GHG Tailoring Rule and determine what constitutes best available control technology for GHG. MidAmerican Energy has obtained and is in the process of obtaining permits to install emissions reduction equipment at existing facilities to comply with CSAPR and was required to assess the impacts of the projects on GHG emissions. A GHG emissions limit will be imposed on the permits for those projects. PacifiCorp is in the process of obtaining permits for certain existing facilities to install emissions reduction equipment to comply with the Regional Haze Rules and assessed the impacts of the projects on GHG emissions under the GHG Tailoring Rule. No GHG emissions limit is expected to be included in the permits. However, PacifiCorp's Lake Side 2 was subject to a best available control technology review and the permit includes a limit for carbon dioxide equivalent emissions. The GHG Tailoring Rule will result in the imposition of a permit limit for GHG emissions at certain facilities, which management believes will not have a material impact on the Company.

GHG New Source Performance Standards

Under the Clean Air Act, the EPA may establish emissions standards that reflect the degree of emission reductions achievable through the best technology that has been demonstrated, taking into consideration the cost of achieving those reductions and any non-air quality health and environmental impact and energy requirements. The EPA entered into a settlement agreement with a number of parties, including certain state governments and environmental groups, in December 2010 to promulgate emissions standards covering GHG by September 30, 2011, as amended, and issue final regulations by May 26, 2012. However, in mid-September, the EPA indicated it would not meet the September 30, 2011 deadline to promulgate the standards and it has not yet established a new schedule for issuing the proposed rules. It is unclear what standards the EPA will establish for new and modified sources or what the guidelines will be for existing sources. Until the standards are proposed and finalized, the impact on the Company cannot be determined.

Regional and State Activities

Several states have promulgated or otherwise participate in state-specific or regional laws or initiatives to report or mitigate GHG emissions. These are expected to impact PacifiCorp, MidAmerican Energy and other MEHC energy subsidiaries and include:

- The Western Climate Initiative, a comprehensive regional effort to reduce GHG emissions by 15% below 2005 levels by 2020 through a cap-and-trade program that includes the electricity sector. The Western Climate Initiative includes the states of California, Montana, New Mexico, Oregon, Utah and Washington and the Canadian provinces of British Columbia, Manitoba, Ontario and Quebec. The state and provincial partners have agreed to begin reporting GHG emissions in 2011 for emissions that occurred in 2010. The first phase of the cap-and-trade program is scheduled to begin on January 1, 2012; however, only California, British Columbia and Quebec appear to be in a position to implement their programs in 2012.
- In October 2011, the California Air Resources Board adopted a GHG cap-and-trade program that will be implemented effective January 1, 2012, and will impose compliance obligations on entities in 2013. In addition, California law imposes a GHG emissions performance standard to all electricity generated within the state or delivered from outside the state that is no higher than the GHG emissions levels of a state-of-the-art combined-cycle natural gas-fired generating facility, as well as legislation that adopts an economy-wide cap on GHG emissions to 1990 levels by 2020.
- In November 2007, the Iowa governor signed the Midwest Greenhouse Gas Accord and the Energy Security and Climate Stewardship Platform for the Midwest. The signatories to the platform were other Midwestern states that agreed to implement a regional cap-and-trade system for GHG emissions. Advisory group recommendations included the assessment of 2020 emissions reduction targets of 15%, 20% and 25% below 2005 levels and a 2050 target of 60% to 80% below 2005 levels. In addition, the accord calls for the participating states to collectively meet at least 2% of regional annual retail sales of electricity and natural gas through energy efficiency improvements by 2015 and continue to achieve an additional 2% in efficiency improvements every year thereafter. There has been no further progress in implementing a Midwest regional cap-and-trade program.
- The Regional Greenhouse Gas Initiative, a mandatory, market-based effort to reduce GHG emissions in ten Northeastern and Mid-Atlantic states, requires, beginning in 2009, the reduction of carbon dioxide emissions from the power sector of 10% by 2018. In May 2011, New Jersey withdrew from participation in the Regional Greenhouse Gas Initiative and in June 2011 a lawsuit filed in New York alleged that the state of New York unlawfully joined the Regional Greenhouse Gas Initiative without legislative approval.

GHG Litigation

In September 2009, the United States Court of Appeals for the Second Circuit ("Second Circuit") issued its opinion in the case of *Connecticut v. American Electric Power, et al*, which remanded to the lower court a nuisance action by eight states and the City of New York against five large utility emitters of carbon dioxide. The United States District Court for the Southern District of New York ("Southern District of New York") dismissed the case in 2005, holding that the claims that GHG emissions from the defendants' coal-fueled generating facilities were causing harmful climate change and should be enjoined as a public nuisance under federal common law presented a "political question" that the court lacked jurisdiction to decide. The Second Circuit rejected this conclusion and stated the Southern District of New York was not precluded from determining the case on its merits. In December 2010, the United States Supreme Court agreed to hear the case on appeal from the Second Circuit. After oral arguments were heard by the United States Supreme Court in April 2011, the United States Supreme Court issued its decision in June 2011 dismissing the federal common law claim of nuisance and holding that the Clean Air Act provides a means to seek limits on emissions of carbon dioxide on power plants.

Reporting

California mandatory GHG reporting requirements began with 2008 emissions and PacifiCorp has reported its emissions annually since their inception. In September 2009, the EPA issued its final rule regarding mandatory GHG Reporting beginning January 1, 2010. Under GHG Reporting, suppliers of fossil fuels, manufacturers of vehicles and engines, and facilities that emit 25,000 metric tons or more per year of GHG are required to submit annual reports to the EPA. PacifiCorp, MidAmerican Energy and CalEnergy U.S. are subject to this requirement and submitted their first reports prior to September 30, 2011. Northern Natural Gas and Kern River reported their combustion-related GHG emissions prior to September 30, 2011, and are required to report their GHG emissions from equipment leaks and venting by March 31, 2012.

Federal Legislation

Legislation introduced in the 112th Congress has been focused on repeal or delay of the EPA's ability to regulate GHG emissions. There is currently no federal legislation pending to regulate GHG emissions.

Renewable Portfolio Standards

In 2011, the California Legislature passed, and the governor signed, legislation to expand the state's RPS to require an average of 20% of retail load to be procured from renewable resources by December 31, 2013, 25% by December 31, 2016 and 33% by December 31, 2020 and each year thereafter. The new law supersedes the California Air Resources Board 33% renewable electricity standard adopted pursuant to Executive Order S-21-09 in September 2009. The 2011 legislation expands the RPS to all California retail sellers, changes the flexible compliance mechanisms for retail sellers, and limits the use of out-of-state renewable electricity generation to comply with the law.

Water Quality Standards

In March 2011, the EPA released a proposed rule under §316(b) of the Clean Water Act to regulate cooling water intakes at existing facilities. The proposed rule establishes requirements for all power generating facilities that withdraw more than 2 million gallons per day, based on total design intake capacity, of water from waters of the United States and use at least 25% of the withdrawn water exclusively for cooling purposes. The proposed rule includes impingement (i.e., when fish and other organisms are trapped against screens when water is drawn into a facility's cooling system) mortality standards to be met through average impingement mortality or intake velocity design criteria and entrainment (i.e., when organisms are drawn into the facility) standards to be determined on a case-by-case basis. The standards are required to be met as soon as possible after the effective date of the final rule, but no later than eight years thereafter. The rule is required to be finalized by the EPA by July 2012. PacifiCorp and MidAmerican Energy will be required to complete impingement and entrainment studies in 2013. The costs of compliance with the cooling water intake structure rule cannot be determined until the rule is final and the prescribed studies are conducted. In the event that PacifiCorp's or MidAmerican Energy's existing intake structures require modification, the costs are not anticipated to be significant.

Coal Combustion Byproduct Disposal

In December 2008, an ash impoundment dike at the Tennessee Valley Authority's Kingston power plant collapsed after heavy rain, releasing a significant amount of fly ash and bottom ash, coal combustion byproducts, and water to the surrounding area. In light of this incident, federal and state officials have called for greater regulation of the storage and disposal of coal combustion byproducts. In May 2010, the EPA released a proposed rule to regulate the management and disposal of coal combustion byproducts, presenting two alternatives to regulation under the RCRA. Under the first option, coal combustion byproducts would be regulated as special waste under RCRA Subtitle C and the EPA would establish requirements for coal combustion byproducts from the point of generation to disposition, including the closure of disposal units. Alternatively, the EPA is considering regulation under RCRA Subtitle D under which it would establish minimum nationwide standards for the disposal of coal combustion byproducts. Under both options, surface impoundments utilized for coal combustion byproducts would have to be cleaned and closed unless they could meet more stringent regulatory requirements; in addition, more stringent requirements would be implemented for new ash landfills and expansions of existing ash landfills. PacifiCorp operates 16 surface impoundments and six landfills that contain coal combustion byproducts. MidAmerican Energy operates eight surface impoundments and four landfills that contain coal combustion byproducts. These ash impoundments and landfills may be impacted by the newly proposed regulation, particularly if the materials are regulated as hazardous or special waste under RCRA Subtitle C, and could pose significant additional costs associated with ash management and disposal activities at the Company's coal-fired generating facilities. The public comment period closed in November 2010. The EPA has indicated it does not intend to finalize the rule in 2011 and the substance of the final rule is not known. The impact of the proposed regulations on coal combustion byproducts cannot be determined at this time; however, both PacifiCorp and MidAmerican Energy have begun developing surface impoundment and landfill compliance plan options to ensure that physical infrastructure decisions are aligned with the potential outcomes of the rulemaking.

Other

MEHC expects its Domestic Regulated Businesses will be allowed to recover the prudently incurred costs to comply with the environmental laws and regulations discussed above. The Company's planning efforts take into consideration the complexity of balancing factors such as: (1) pending environmental regulations and requirements to reduce emissions, address waste disposal, ensure water quality, and protect wildlife; (2) avoidance of excessive reliance on any one generation technology; (3) costs and trade-offs of various resource options including energy efficiency, demand response programs, and renewable generation; (4) state-specific energy policies, resource preferences, and economic development efforts; (5) additional transmission investment to reduce power costs and increase efficiency and reliability of the integrated transmission system; and (6) keeping rates as affordable as possible. Due to the number of generating units impacted by environmental regulations, deferring installation of compliance-related projects is often not feasible or cost effective and places the Company at risk of not having access to necessary capital, material, and labor while attempting to perform major equipment installations in a compressed timeframe concurrent with other utilities across the country. Therefore, the Company has established installation schedules with permitting agencies that coordinate compliance timeframes with construction and tie-in of major environmental compliance projects as units are scheduled off-line for planned maintenance outages; these coordinated efforts reduce costs associated with replacement power and maintain system reliability.

Collateral and Contingent Features

Debt and preferred securities of MEHC and certain of its subsidiaries are rated by credit rating agencies. Assigned credit ratings are based on each rating agency's assessment of the rated company's ability to, in general, meet the obligations of its issued debt or preferred securities. The credit ratings are not a recommendation to buy, sell or hold securities, and there is no assurance that a particular credit rating will continue for any given period of time.

MEHC and its subsidiaries have no credit rating downgrade triggers that would accelerate the maturity dates of outstanding debt, and a change in ratings is not an event of default under the applicable debt instruments. The Company's unsecured revolving credit facilities do not require the maintenance of a minimum credit rating level in order to draw upon their availability but, under certain instances, must maintain sufficient covenant tests if ratings drop below a certain level. However, commitment fees and interest rates under the credit facilities are tied to credit ratings and increase or decrease when the ratings change. A ratings downgrade could also increase the future cost of commercial paper, short- and long-term debt issuances or new credit facilities.

In accordance with industry practice, certain wholesale agreements, including derivative contracts, contain provisions that require certain of MEHC's subsidiaries, principally the Utilities, to maintain specific credit ratings on their unsecured debt from one or more of the three recognized credit rating agencies. These agreements, including derivative contracts, may either specifically provide bilateral rights to demand cash or other security if credit exposures on a net basis exceed specified rating-dependent threshold levels ("credit-risk-related contingent features") or provide the right for counterparties to demand "adequate assurance" in the event of a material adverse change in the subsidiary's creditworthiness. These rights can vary by contract and by counterparty. As of September 30, 2011, these subsidiary's credit ratings from the three recognized credit rating agencies were investment grade. If all credit-risk-related contingent features or adequate assurance provisions for these agreements, including derivative contracts, had been triggered as of September 30, 2011, the Company would have been required to post $558 million of additional collateral. The Company's collateral requirements could fluctuate considerably due to market price volatility, changes in credit ratings, changes in legislation or regulation, or other factors. Refer to Note 6 of Notes to Consolidated Financial Statements in Item 1 of this Form 10-Q for a discussion of the Company's collateral requirements specific to the Company's derivative contracts.

In July 2010, the President signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act ("Reform Act"). The Reform Act reshapes financial regulation in the United States by creating new regulators, regulating new markets and firms, and providing new enforcement powers to regulators. Virtually all major areas of the Reform Act, including collateral requirements on derivative contracts, are the subject of regulatory interpretation and implementation rules requiring rulemaking proceedings that may take several years to complete.

The Company is a party to derivative contracts, including over-the-counter derivative contracts. The Reform Act provides for extensive new regulation of over-the-counter derivative contracts and certain market participants, including imposition of mandatory clearing, exchange trading, capital and margin requirements for "swap dealers" and "major swap participants." The Reform Act provides certain exemptions from these regulations for commercial end-users that use derivatives to hedge and manage the commercial risk of their businesses. Although the Company generally does not enter into over-the-counter derivative contracts for purposes unrelated to hedging of commercial risk and does not believe it will be considered a swap dealer or major swap participant, the outcome of the rulemaking proceedings cannot be predicted and, therefore, the impact of the Reform Act on the Company's consolidated financial results cannot be determined at this time.

New Accounting Pronouncements

For a discussion of new accounting pronouncements affecting the Company, refer to Note 2 of Notes to Consolidated Financial Statements in Item 1 of this Form 10-Q.

Critical Accounting Estimates

Certain accounting measurements require management to make estimates and judgments concerning transactions that will be settled several years in the future. Amounts recognized on the Consolidated Financial Statements based on such estimates involve numerous assumptions subject to varying and potentially significant degrees of judgment and uncertainty. Accordingly, the amounts currently reflected on the Consolidated Financial Statements will likely change in the future as additional information becomes available. Estimates are used for, but not limited to, the accounting for the effects of certain types of regulation, derivatives, impairment of long-lived assets and goodwill, pension and other postretirement benefits, income taxes and revenue recognition - unbilled revenue. For additional discussion of the Company's critical accounting estimates, see Item 7 of the Company's Annual Report on Form 10-K for the year ended December 31, 2010. There have been no significant changes in the Company's assumptions regarding critical accounting estimates since December 31, 2010.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

For quantitative and qualitative disclosures about market risk affecting the Company, see Item 7A of the Company's Annual Report on Form 10-K for the year ended December 31, 2010. The Company's exposure to market risk and its management of such risk has not changed materially since December 31, 2010. Refer to Note 6 of Notes to Consolidated Financial Statements in Item 1 of this Form 10-Q for disclosure of the Company's derivative positions as of September 30, 2011.

Item 4. Controls and Procedures

At the end of the period covered by this Quarterly Report on Form 10-Q, the Company carried out an evaluation, under the supervision and with the participation of the Company's management, including the Chief Executive Officer (principal executive officer) and the Chief Financial Officer (principal financial officer), of the effectiveness of the design and operation of the Company's disclosure controls and procedures (as defined in Rule 13a-15(e) promulgated under the Securities and Exchange Act of 1934, as amended). Based upon that evaluation, the Company's management, including the Chief Executive Officer (principal executive officer) and the Chief Financial Officer (principal financial officer), concluded that the Company's disclosure controls and procedures were effective to ensure that information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the United States Securities and Exchange Commission's rules and forms, and is accumulated and communicated to management, including the Company's Chief Executive Officer (principal executive officer) and Chief Financial Officer (principal financial officer), or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure. There has been no change in the Company's internal control over financial reporting during the quarter ended September 30, 2011 that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

PART II

Item 1. Legal Proceedings

None.

Item 1A. Risk Factors

There has been no material change to the Company's risk factors from those disclosed in Item 1A of the Company's Annual Report on Form 10-K for the year ended December 31, 2010.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

Not applicable.

Item 3. Defaults Upon Senior Securities

Not applicable.

Item 4. (Removed and Reserved)

Item 5. Other Information

Coal Mine Safety Disclosures Required by the Dodd-Frank Wall Street Reform and Consumer Protection Act

The operation of PacifiCorp's coal mines and coal processing facilities is regulated by the MSHA under the Mine Safety Act. MSHA inspects PacifiCorp's coal mines and coal processing facilities on a regular basis and may issue citations, notices, orders, or any combination thereof, when it believes a violation has occurred under the Mine Safety Act. For citations, monetary penalties are assessed by MSHA. Citations, notices and orders can be contested and appealed and the severity and assessment of penalties may be reduced or, in some cases, dismissed through the appeal process.

The table below summarizes the total number of citations, notices and orders issued and penalties assessed by MSHA for each coal mine or coal processing facility operated by PacifiCorp under the indicated provisions of the Mine Safety Act during the nine-month period ended September 30, 2011. Legal actions pending before the Federal Mine Safety and Health Review Commission, which are not exclusive to citations, notices, orders and penalties assessed by MSHA, are as of September 30, 2011. Closed or idled mines have been excluded from the table below as no citations, orders or notices were issued for such mines during the nine-month period ended September 30, 2011. In addition, there were no fatalities at PacifiCorp's coal mines or coal processing facilities during the nine-month period ended September 30, 2011.

	Mine Safety Act							
Coal Mine or Coal Processing Facility	Section 104 Significant & Substantial Citations	Section 104(b) Orders	Section 104(d) Citations & Orders	Section 110(b)(2) Citations	Section 107(a) Imminent Danger Orders	Section 104(e) Notice	Total Value of Proposed MSHA Assessments (in thousands)	Legal Actions Pending
Deer Creek	14	—	—	—	—	—	$ 29	12
Bridger (surface)	6	—	—	—	—	—	10	6
Bridger (underground)	32	1	—	—	—	—	120	18
Cottonwood Preparatory Plant	1	—	—	—	—	—	—	—
Wyodak Coal Crushing Facility	—	—	—	—	—	—	—	—

Item 6. Exhibits

The exhibits listed on the accompanying Exhibit Index are filed as part of this Quarterly Report.

SIGNATURES

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

MIDAMERICAN ENERGY HOLDINGS COMPANY
(Registrant)

Date: November 4, 2011

/s/ Patrick J. Goodman
Patrick J. Goodman
Senior Vice President and Chief Financial Officer
(principal financial and accounting officer)

EXHIBIT INDEX

Exhibit No.	Description
15	Awareness Letter of Independent Registered Public Accounting Firm.
31.1	Principal Executive Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Principal Financial Officer Certification Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Principal Executive Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	Principal Financial Officer Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101	The following financial information from MidAmerican Energy Holdings Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2011, is formatted in XBRL (eXtensible Business Reporting Language) and included herein: (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Operations, (iii) the Consolidated Statements of Cash Flows, (iv) the Consolidated Statements of Changes in Equity, (v) the Consolidated Statements of Comprehensive Income, and (vi) the Notes to Consolidated Financial Statements, tagged as blocks of text.

EXHIBIT 15

AWARENESS LETTER OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

MidAmerican Energy Holdings Company
Des Moines, Iowa

We have reviewed, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the unaudited consolidated interim financial information of MidAmerican Energy Holdings Company and subsidiaries for the periods ended September 30, 2011 and 2010, as indicated in our report dated November 4, 2011; because we did not perform an audit, we expressed no opinion on that information.

We are aware that our report referred to above, which is included in your Quarterly Report on Form 10-Q for the quarter ended September 30, 2011, is incorporated by reference in Registration Statement No. 333-147957 on Form S-8.

We also are aware that the aforementioned report, pursuant to Rule 436(c) under the Securities Act of 1933, is not considered a part of the Registration Statement prepared or certified by an accountant or a report prepared or certified by an accountant within the meaning of Sections 7 and 11 of that Act.

/s/ Deloitte & Touche LLP

Des Moines, Iowa
November 4, 2011

EXHIBIT 31.1

**CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Gregory E. Abel, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of MidAmerican Energy Holdings Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 4, 2011

/s/ Gregory E. Abel
Gregory E. Abel
Chairman, President and Chief Executive Officer
(principal executive officer)

EXHIBIT 31.2

CERTIFICATION PURSUANT TO
SECTION 302 OF THE
SARBANES-OXLEY ACT OF 2002

I, Patrick J. Goodman, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q of MidAmerican Energy Holdings Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

    (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 4, 2011

/s/ Patrick J. Goodman
Patrick J. Goodman
Senior Vice President and Chief Financial Officer
(principal financial officer)

EXHIBIT 32.1

CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

I, Gregory E. Abel, Chairman, President and Chief Executive Officer of MidAmerican Energy Holdings Company (the “Company”), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Quarterly Report on Form 10-Q of the Company for the quarterly period ended September 30, 2011 (the “Report”) fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

Date: November 4, 2011

/s/ Gregory E. Abel
Gregory E. Abel
Chairman, President and Chief Executive Officer
(principal executive officer)

EXHIBIT 32.2

**CERTIFICATION PURSUANT TO
SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002**

I, Patrick J. Goodman, Senior Vice President and Chief Financial Officer of MidAmerican Energy Holdings Company (the "Company"), certify, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, 18 U.S.C. Section 1350, that to the best of my knowledge:

(1) the Quarterly Report on Form 10-Q of the Company for the quarterly period ended September 30, 2011 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(2) the information contained in the Report fairly presents, in all material respects, the financial condition and result of operations of the Company.

Date: November 4, 2011

/s/ Patrick J. Goodman
Patrick J. Goodman
Senior Vice President and Chief Financial Officer
(principal financial officer)