

**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, 2010

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, 2010, 74,609,001 shares of common stock were outstanding.

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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, 2010, and the related consolidated statements of operations and comprehensive income for the three-month and nine-month periods ended September 30, 2010 and 2009, and of cash flows and changes in equity for the nine-month periods ended September 30, 2010 and 2009. 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, 2009, 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 March 1, 2010, 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, 2009 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 5, 2010

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

	As of	
	September 30, 2010	December 31, 2009
ASSETS		
Current assets:		
Cash and cash equivalents	\$ 521	\$ 429
Trade receivables, net	1,097	1,308
Income taxes receivable	440	88
Inventories	578	591
Derivative contracts	175	136
Investments and restricted cash and investments	101	83
Other current assets	372	458
Total current assets	3,284	3,093
Property, plant and equipment, net	31,469	30,936
Goodwill	5,036	5,078
Investments and restricted cash and investments	2,464	2,702
Regulatory assets	2,300	2,093
Derivative contracts	30	52
Other assets	940	730
Total assets	\$ 45,523	\$ 44,684

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, 2010	December 31, 2009
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	\$ 798	\$ 918
Accrued interest	337	344
Accrued property, income and other taxes	303	277
Derivative contracts	204	123
Short-term debt	226	179
Current portion of long-term debt	792	379
Other current liabilities	782	683
Total current liabilities	3,442	2,903
Regulatory liabilities	1,633	1,603
Derivative contracts	468	458
MEHC senior debt	5,371	5,371
MEHC subordinated debt	193	402
Subsidiary debt	13,187	13,600
Deferred income taxes	6,185	5,604
Other long-term liabilities	1,634	1,900
Total liabilities	32,113	31,841
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	5,439	5,453
Retained earnings	7,600	6,788
Accumulated other comprehensive income, net	143	335
Total MEHC shareholders' equity	13,182	12,576
Noncontrolling interests	228	267
Total equity	13,410	12,843
Total liabilities and equity	\$ 45,523	\$ 44,684

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,	
	2010	2009	2010	2009
Operating revenue:				
Energy	\$ 2,510	\$ 2,429	\$ 7,537	\$ 7,448
Real estate	253	312	793	764
Total operating revenue	<u>2,763</u>	<u>2,741</u>	<u>8,330</u>	<u>8,212</u>
Operating costs and expenses:				
Energy:				
Cost of sales	976	875	2,956	2,818
Operating expense	577	598	1,799	1,908
Depreciation and amortization	316	313	939	916
Real estate	250	294	773	748
Total operating costs and expenses	<u>2,119</u>	<u>2,080</u>	<u>6,467</u>	<u>6,390</u>
Operating income	<u>644</u>	<u>661</u>	<u>1,863</u>	<u>1,822</u>
Other income (expense):				
Interest expense	(309)	(316)	(923)	(957)
Capitalized interest	14	12	42	30
Interest and dividend income	4	8	24	36
Other, net	33	41	89	119
Total other income (expense)	<u>(258)</u>	<u>(255)</u>	<u>(768)</u>	<u>(772)</u>
Income before income tax expense and equity income	386	406	1,095	1,050
Income tax expense	38	39	165	211
Equity income	(24)	(21)	(29)	(49)
Net income	<u>372</u>	<u>388</u>	<u>959</u>	<u>888</u>
Net income attributable to noncontrolling interests	8	12	100	24
Net income attributable to MEHC	<u>\$ 364</u>	<u>\$ 376</u>	<u>\$ 859</u>	<u>\$ 864</u>

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,	
	2010	2009
Cash flows from operating activities:		
Net income	\$ 959	\$ 888
Adjustments to reconcile net income to net cash flows from operating activities:		
Gain on other items, net	(52)	(4)
Depreciation and amortization	950	929
Stock-based compensation	—	123
Changes in regulatory assets and liabilities	25	28
Provision for deferred income taxes	572	700
Other, net	(32)	(39)
Changes in other operating assets and liabilities:		
Trade receivables and other assets	174	293
Derivative collateral, net	(93)	93
Trading securities	—	499
Contributions to pension and other postretirement benefit plans, net	(139)	(74)
Accounts payable and other liabilities	(284)	(453)
Net cash flows from operating activities	<u>2,080</u>	<u>2,983</u>
Cash flows from investing activities:		
Capital expenditures	(1,862)	(2,592)
Purchases of available-for-sale securities	(77)	(483)
Proceeds from sales of available-for-sale securities	65	242
Proceeds from Constellation Energy 14% note	—	1,000
Proceeds from sale of assets and business, net	140	—
Other, net	(63)	(13)
Net cash flows from investing activities	<u>(1,797)</u>	<u>(1,846)</u>
Cash flows from financing activities:		
Proceeds from MEHC senior debt	—	250
Repayments of MEHC subordinated debt	(259)	(667)
Proceeds from subsidiary debt	231	992
Repayments of subsidiary debt	(142)	(383)
Net proceeds from (repayments of) MEHC revolving credit facility	142	(216)
Net repayments of subsidiary short-term debt	(87)	(506)
Net purchases of common stock	(56)	(123)
Other, net	(19)	(23)
Net cash flows from financing activities	<u>(190)</u>	<u>(676)</u>
Effect of exchange rate changes	<u>(1)</u>	<u>3</u>
Net change in cash and cash equivalents	92	464
Cash and cash equivalents at beginning of period	429	280
Cash and cash equivalents at end of period	<u>\$ 521</u>	<u>\$ 744</u>

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							Total Equity
	Common		Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive (Loss) Income, Net	Noncontrolling Interests		
	Shares	Stock						
Balance, January 1, 2009	75	\$ —	\$ 5,455	\$ 5,631	\$ (879)	\$ 270	\$ 10,477	
Net income	—	—	—	864	—	24	888	
Other comprehensive income	—	—	—	—	1,182	—	1,182	
Stock-based compensation	—	—	123	—	—	—	123	
Exercise of common stock options	1	—	25	—	—	—	25	
Common stock purchases	(1)	—	(148)	—	—	—	(148)	
Contributions	—	—	—	—	—	23	23	
Distributions	—	—	—	—	—	(53)	(53)	
Other equity transactions	—	—	(2)	—	—	13	11	
Balance, September 30, 2009	75	\$ —	\$ 5,453	\$ 6,495	\$ 303	\$ 277	\$ 12,528	
Balance, January 1, 2010	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, September 30, 2010	75	\$ —	\$ 5,439	\$ 7,600	\$ 143	\$ 228	\$ 13,410	

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,	
	2010	2009	2010	2009
Net income	\$ 372	\$ 388	\$ 959	\$ 888
Other comprehensive income (loss), net of tax:				
Unrecognized amounts on retirement benefits, net of tax of \$-, \$6, \$18 and \$(8)	(23)	13	23	(24)
Foreign currency translation adjustment	123	(73)	(86)	231
Fair value adjustment on cash flow hedges, net of tax of \$(14), \$3, \$(12) and \$(5)	(21)	7	(18)	(6)
Unrealized gains (losses) on marketable securities, net of tax of \$51, \$651, \$(73) and \$653	77	978	(111)	981
Total other comprehensive income (loss), net of tax	156	925	(192)	1,182
Comprehensive income	528	1,313	767	2,070
Comprehensive income attributable to noncontrolling interests	8	12	100	24
Comprehensive income attributable to MEHC	\$ 520	\$ 1,301	\$ 667	\$ 2,046

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

MIDAMERICAN ENERGY HOLDINGS COMPANY AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

(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 President and Chief Executive Officer. As of September 30, 2010, 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 is 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"), CE Electric UK Funding Company ("CE Electric UK") (which primarily consists of Northern Electric Distribution Limited ("Northern Electric") and Yorkshire Electricity Distribution plc ("Yorkshire Electricity")), CalEnergy Philippines (which owns a majority interest in the Casecan 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, MEHC 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.

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, 2010 and for the three- and nine-month periods ended September 30, 2010 and 2009. The results of operations for the three- and nine-month periods ended September 30, 2010 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, 2009 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, 2010.

(2) New Accounting Pronouncements

In January 2010, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2010-06 ("ASU No. 2010-06"), which amends FASB Accounting Standards Codification ("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 is effective for fiscal years beginning after December 15, 2010, and for interim periods within those fiscal years. The adoption did not have a material impact on the Company's disclosures included within Notes to Consolidated Financial Statements.

In June 2009, the FASB issued authoritative guidance (which was codified into ASC Topic 810, "Consolidation," with the issuance of ASU No. 2009-17) that requires a primarily qualitative analysis to determine if an enterprise is the primary beneficiary of a variable interest entity. This analysis is based on whether the enterprise has (a) the power to direct the activities of the variable interest entity that most significantly impact the entity's economic performance and (b) the obligation to absorb losses of the entity or the right to receive benefits from the entity that could potentially be significant to the variable interest entity. In addition, enterprises are required to more frequently reassess whether an entity is a variable interest entity and whether the enterprise is the primary beneficiary of the variable interest entity. Finally, the guidance for consolidation or deconsolidation of a variable interest entity is amended and disclosure requirements about an enterprise's involvement with a variable interest entity are enhanced. The Company adopted this guidance as of January 1, 2010 on a prospective basis. As a result, PacifiCorp's coal mining joint venture, Bridger Coal Company ("Bridger Coal"), was deconsolidated and is being accounted for under the equity method of accounting as the power to direct the activities that most significantly impact Bridger Coal's economic performance are shared with the joint venture partner. The deconsolidation of Bridger Coal resulted in a decrease in assets, liabilities and noncontrolling interest equity as of January 1, 2010 of \$192 million, \$108 million and \$84 million, respectively.

(3) Property, Plant and Equipment, Net

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

	Depreciable Life	As of	
		September 30, 2010	December 31, 2009
Regulated assets:			
Utility generation, distribution and transmission system	5-85 years	\$ 36,322	\$ 35,616
Interstate pipeline assets	3-67 years	5,880	5,809
		42,202	41,425
Accumulated depreciation and amortization		(13,581)	(13,336)
Regulated assets, net		28,621	28,089
Nonregulated assets:			
Independent power plants	10-30 years	678	677
Other assets	3-30 years	417	480
		1,095	1,157
Accumulated depreciation and amortization		(480)	(462)
Nonregulated assets, net		615	695
Net operating assets		29,236	28,784
Construction in progress		2,233	2,152
Property, plant and equipment, net		\$ 31,469	\$ 30,936

Substantially all of the construction in progress as of September 30, 2010 and December 31, 2009 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, 2009.

Rate Matters

Kern River Rate Case

In January 2009, the Federal Energy Regulatory Commission ("FERC") ordered Kern River to file compliance rates based on an allowed return on equity of 11.55%. Kern River made the initial compliance filing in March 2009, and a revised filing in September 2009. A request for rehearing of the FERC's January 2009 order, as well as comments and protests on Kern River's March 2009 and September 2009 compliance filings, were timely filed. In December 2009, the FERC issued an order establishing rates for the period of Kern River's current long-term contracts ("Period One rates"), and affirmed its prior opinion with regard to Kern River's allowed return, while requiring that rates be leveled 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 settlement processes, and a hearing should settlement processes fail. Kern River made a compliance filing conforming its Period One rates to the FERC's order in January 2010 and filed illustrative Period Two rates in February 2010 as required by the FERC's order. Also in January 2010, Kern River filed a request for rehearing of the FERC's December 2009 order and filed in the United States Court of Appeals for the District of Columbia Circuit ("DC Circuit") a request for review of the rulings in the FERC's December 2009 order. In March 2010, Kern River sought and was granted the FERC's authority to issue provisional refunds to its shippers subject to its right of recoupment, if necessary, based on the final rulings in the matter. Also in March 2010, the settlement discussions ordered by the FERC regarding Period Two rates reached an impasse and were terminated. Discovery commenced under a contested case procedural schedule and Kern River filed testimony in June and September 2010. Also in June 2010, the DC Circuit dismissed Kern River's request for review without prejudice to its ability to re-file when all the proceedings at the FERC, including those related to Period Two rates, are concluded. Also in September 2010, Kern River filed with the FERC regarding Period One rates a motion for clarification related to recovery of certain regulatory assets and a tariff filing for a periodic rate adjustment, which will not be necessary if the requested clarification is granted. Final testimony in the Period Two rates phase of the proceeding was filed in October 2010. Formal hearings for Period Two rates are scheduled to commence in December 2010.

Oregon Senate Bill 408

Oregon Senate Bill 408 ("SB 408") requires PacifiCorp and other large regulated, investor-owned utilities that provide electric or natural gas service to Oregon customers to file an annual report each October with the Oregon Public Utility Commission ("OPUC") comparing income taxes collected and income taxes paid, as defined by the statute and its administrative rules. If after its review, the OPUC determines the amount of income taxes collected differs from the amount of income taxes paid by more than \$100,000, the OPUC must require the public utility to establish an automatic adjustment clause to account for the difference.

The OPUC's April 2008 order approving the recovery of \$35 million, plus interest, related to PacifiCorp's 2006 tax report is being challenged by the Industrial Customers of Northwest Utilities, which has petitioned the Oregon Court of Appeals for judicial review of, among other things, the application of certain administrative rules considered in the April 2008 order. In July 2010, the Oregon Court of Appeals held oral arguments on the matter. A decision is not expected until 2011, which could impact PacifiCorp's 2006 through 2009 tax reports filed under SB 408. PacifiCorp believes the outcome of these proceedings will not have a material impact on its consolidated financial results. The \$35 million, plus interest, was previously recorded in earnings.

In October 2009, PacifiCorp filed for a surcharge of \$38 million in its 2008 tax report under SB 408. In January 2010, PacifiCorp entered into a stipulation with OPUC staff and the Citizens' Utility Board of Oregon, agreeing to a lower surcharge totaling \$2 million, including interest. In April 2010, the OPUC issued an order adopting the stipulation in its entirety, at which time PacifiCorp recorded the \$2 million in earnings.

In October 2010, PacifiCorp filed for a surcharge of \$29 million, plus interest, in its 2009 tax report under SB 408. No amounts have been recorded in relation to the 2009 tax report.

(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				Total
	Level 1	Level 2	Level 3	Other ⁽¹⁾	
As of September 30, 2010					
Assets:					
Commodity derivatives	\$ 5	\$ 422	\$ 32	\$ (254)	\$ 205
Investments in available-for-sale securities:					
Money market mutual funds ⁽²⁾	378	—	—	—	378
Debt securities	86	41	41	—	168
Equity securities	2,026	—	—	—	2,026
Investments in trading securities - Equity	9	—	—	—	9
	<u>\$ 2,504</u>	<u>\$ 463</u>	<u>\$ 73</u>	<u>\$ (254)</u>	<u>\$ 2,786</u>
Liabilities:					
Commodity derivatives	\$ (19)	\$ (693)	\$ (359)	\$ 399	\$ (672)
As of December 31, 2009					
Assets:					
Commodity derivatives	\$ 3	\$ 318	\$ 36	\$ (169)	\$ 188
Investments in available-for-sale securities:					
Money market mutual funds ⁽²⁾	376	—	—	—	376
Debt securities	70	79	46	—	195
Equity securities	2,230	8	—	—	2,238
	<u>\$ 2,679</u>	<u>\$ 405</u>	<u>\$ 82</u>	<u>\$ (169)</u>	<u>\$ 2,997</u>
Liabilities:					
Commodity derivatives	\$ (5)	\$ (395)	\$ (395)	\$ 218	\$ (577)
Interest rate derivative	—	(4)	—	—	(4)
	<u>\$ (5)</u>	<u>\$ (399)</u>	<u>\$ (395)</u>	<u>\$ 218</u>	<u>\$ (581)</u>

(1) Represents netting under master netting arrangements and a net cash collateral receivable of \$145 million and \$49 million as of September 30, 2010 and December 31, 2009, 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.

When available, the fair value of derivative contracts is determined using unadjusted quoted prices for identical contracts on the applicable exchange in which the Company transacts. When quoted prices for identical contracts are not available, the Company uses forward price curves derived from 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. 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 significant unobservable inputs. Refer to Note 6 for further discussion regarding the Company's risk management and hedging activities.

The Company's investments in money market mutual funds and debt and equity securities are accounted for as either available-for-sale or trading 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):

	<u>Three-Month Period Ended September 30, 2010</u>		<u>Three-Month Period Ended September 30, 2009</u>	
	<u>Commodity Derivatives</u>	<u>Debt Securities</u>	<u>Commodity Derivatives</u>	<u>Debt Securities</u>
Beginning balance	\$ (390)	\$ 41	\$ (360)	\$ 38
Changes included in earnings ⁽¹⁾	10	—	(3)	—
Changes in fair value recognized in other comprehensive income	—	—	(1)	2
Changes in fair value recognized in net regulatory assets	14	—	(2)	—
Purchases, sales, issuances and settlements	36	—	33	—
Net transfers (to) from Level 2	3	—	—	—
Ending balance	<u>\$ (327)</u>	<u>\$ 41</u>	<u>\$ (333)</u>	<u>\$ 40</u>
	<u>Nine-Month Period Ended September 30, 2010</u>		<u>Nine-Month Period Ended September 30, 2009</u>	
	<u>Commodity Derivatives</u>	<u>Debt Securities</u>	<u>Commodity Derivatives</u>	<u>Debt Securities</u>
Beginning balance	\$ (359)	\$ 46	\$ (369)	\$ 37
Changes included in earnings ⁽¹⁾	15	—	16	—
Changes in fair value recognized in other comprehensive income	—	(5)	—	3
Changes in fair value recognized in net regulatory assets	(35)	—	32	—
Purchases, sales, issuances and settlements	49	—	11	—
Net transfers (to) from Level 2	3	—	(23)	—
Ending balance	<u>\$ (327)</u>	<u>\$ 41</u>	<u>\$ (333)</u>	<u>\$ 40</u>

- (1) Changes included in earnings are reported as operating revenue on the Consolidated Statements of Operations. For commodity derivatives held as of September 30, 2010 and 2009, net unrealized gains (losses) included in earnings for the three-month periods ended September 30, 2010 and 2009 totaled \$5 million and \$(3) million, respectively, and for the nine-month periods ended September 30, 2010 and 2009 totaled \$10 million and \$12 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, 2010		As of December 31, 2009	
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt	\$ 19,543	\$ 22,464	\$ 19,752	\$ 21,042

(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 and natural gas commodity price risk through MEHC's ownership of PacifiCorp and MidAmerican Energy (the "Utilities") as they have an obligation to serve retail customer load in their regulated service territories. MidAmerican Energy also provides nonregulated retail natural gas and electricity services in competitive markets. The Utilities' load and generation assets 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. Electricity and natural gas prices are subject to wide price swings as supply and demand for these commodities are impacted by, among many other unpredictable items, changing weather, market liquidity, generating facility availability, customer usage, storage, and transmission and transportation constraints. Interest rate risk exists on variable-rate debt, commercial paper 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 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 and by monitoring market changes in interest rates. 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 and interest 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		Total
	Current	Noncurrent	Current	Noncurrent	
As of September 30, 2010					
Not Designated as Hedging Contracts⁽¹⁾⁽²⁾:					
Commodity assets	\$ 280	\$ 43	\$ 44	\$ 69	\$ 436
Commodity liabilities	(82)	(12)	(300)	(529)	(923)
Total	198	31	(256)	(460)	(487)
Designated as Hedging Contracts⁽¹⁾:					
Commodity assets	12	—	6	5	23
Commodity liabilities	(3)	—	(76)	(69)	(148)
Total	9	—	(70)	(64)	(125)
Total derivatives	207	31	(326)	(524)	(612)
Cash collateral (payable) receivable	(32)	(1)	122	56	145
Total derivatives - net basis	\$ 175	\$ 30	\$ (204)	\$ (468)	\$ (467)
As of December 31, 2009					
Not Designated as Hedging Contracts⁽¹⁾⁽²⁾:					
Commodity assets	\$ 219	\$ 70	\$ 22	\$ 31	\$ 342
Commodity liabilities	(30)	(17)	(171)	(476)	(694)
Interest rate liability	—	—	—	(4)	(4)
Total	189	53	(149)	(449)	(356)
Designated as Hedging Contracts⁽¹⁾:					
Commodity assets	5	—	7	3	15
Commodity liabilities	(4)	—	(53)	(44)	(101)
Total	1	—	(46)	(41)	(86)
Total derivatives	190	53	(195)	(490)	(442)
Cash collateral (payable) receivable	(54)	(1)	72	32	49
Total derivatives - net basis	\$ 136	\$ 52	\$ (123)	\$ (458)	\$ (393)

(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, 2010 and December 31, 2009, a net regulatory asset of \$483 million and \$353 million, respectively, was recorded related to the net derivative liability of \$487 million and \$352 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		Nine-Month Periods	
	Ended September 30,		Ended September 30,	
	2010	2009	2010	2009
Beginning balance	\$ 479	\$ 247	\$ 353	\$ 446
Changes in fair value recognized in net regulatory assets	31	15	102	(182)
Net gains reclassified to earnings - operating revenue	10	74	59	243
Net losses reclassified to earnings - cost of sales	(37)	(91)	(31)	(262)
Ending balance	\$ 483	\$ 245	\$ 483	\$ 245

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 and natural gas 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		Nine-Month Periods	
	Ended September 30,		Ended September 30,	
	2010	2009	2010	2009
Commodity derivatives:				
Operating revenue	\$ 10	\$ (2)	\$ 22	\$ 22
Cost of sales	(11)	6	(24)	(5)
Operating expense	—	(1)	(1)	—
Interest rate derivative - interest expense	—	—	4	—
Total	\$ (1)	\$ 3	\$ 1	\$ 17

Designated as Hedging Contracts

The Company uses 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 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 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,			
	2010		2009	
	Commodity Derivatives	Commodity Derivatives	Interest Rate Derivative	Total ⁽¹⁾
Beginning balance	\$ 76	\$ 104	\$ 4	\$ 108
Net losses recognized in OCI	36	34	—	34
Net losses reclassified to earnings - revenue	(1)	(1)	—	(1)
Net losses reclassified to earnings - cost of sales	—	(30)	—	(30)
Ending balance	<u>\$ 111</u>	<u>\$ 107</u>	<u>\$ 4</u>	<u>\$ 111</u>

	Nine-Month Periods Ended September 30,			
	2010		2009	
	Commodity Derivatives	Commodity Derivatives	Interest Rate Derivative	Total ⁽¹⁾
Beginning balance	\$ 81	\$ 83	\$ 6	\$ 89
Net losses (gains) recognized in OCI	54	109	(2)	107
Net gains (losses) reclassified to earnings - revenue	4	(2)	—	(2)
Net losses reclassified to earnings - cost of sales	(28)	(83)	—	(83)
Ending balance	<u>\$ 111</u>	<u>\$ 107</u>	<u>\$ 4</u>	<u>\$ 111</u>

(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 all hedges and hedge ineffectiveness are recognized in income as operating revenue, cost of sales, operating expense or interest expense depending upon the nature of the item being hedged. For the three- and nine-month periods ended September 30, 2010 and 2009, hedge ineffectiveness was insignificant. As of September 30, 2010, the Company had cash flow hedges with expiration dates extending through December 2022 and \$40 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 derivative contracts with fixed price terms that comprise the mark-to-market values as of September 30 (in millions):

	Unit of Measure	2010	2009
Commodity contracts:			
Electricity sales	Megawatt hours	(12)	(20)
Natural gas purchases	Decatherms	242	262
Fuel purchases	Gallons	9	4
Interest rate derivative — variable to fixed swap	Australian dollars	—	59

Credit Risk

The Utilities extend unsecured credit to other utilities, energy marketers, financial institutions and other market participants in conjunction with 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 interest 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., the PJM Interconnection, L.L.C., and the Electric Reliability Council of Texas. 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. 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 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, 2010, 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 \$741 million and \$473 million as of September 30, 2010 and December 31, 2009, respectively, for which the Company had posted collateral of \$174 million and \$99 million, respectively. If all credit-risk-related contingent features for derivative contracts in liability positions had been triggered as of September 30, 2010 and December 31, 2009, the Company would have been required to post \$304 million and \$237 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, 2010	December 31, 2009
Investments:		
BYD common stock	\$ 1,808	\$ 1,986
Rabbi trusts	273	268
Other	101	97
Total investments	2,182	2,351
Restricted cash and investments:		
Nuclear decommissioning trust funds	278	264
Mine reclamation trust funds	—	79
Other	105	91
Total restricted cash and investments	383	434
Total investments and restricted cash and investments	2,565	2,785
Less current portion	(101)	(83)
Noncurrent portion	\$ 2,464	\$ 2,702

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, 2010 and December 31, 2009, the fair value of MEHC's investment in BYD common stock was \$1.808 billion and \$1.986 billion, respectively, which resulted in a pre-tax unrealized gain of \$1.576 billion and \$1.754 billion as of September 30, 2010 and December 31, 2009, respectively.

During 2009, the Company sold 19.9 million shares of Constellation Energy Group, Inc. ("Constellation Energy") common stock for \$536 million, or an average price of \$26.93 per share. For the nine-month period ended September 30, 2009, the Company recognized pre-tax gains on Constellation Energy common stock totaling \$37 million, which are included in other, net on the Consolidated Statements of Operations.

The Company's restricted cash and investments are related to (a) the Company's debt service reserve requirements for certain projects, (b) funds held in trust for nuclear decommissioning and coal mine reclamation and (c) unpaid dividends declared obligations. The debt service funds are restricted by their respective project debt agreements to be used only for the related project. Effective January 1, 2010, the Company deconsolidated Bridger Coal. Refer to Note 2 for further discussion.

(8) Recent Debt Transactions

In July 2010, MEHC called and repaid at par value \$92 million of 6.25% CalEnergy Capital Trust II subordinated debt due in February 2012.

In July 2010, Yorkshire Electricity closed on a £151 million finance contract with the European Investment Bank and issued £151 million of 4.13% notes due July 20, 2022. The net proceeds are being used to fund capital expenditures. Also in July 2010, Northern Electric closed on a £119 million finance contract with the European Investment Bank. Amounts available under the finance contract may be drawn upon through 2011.

In March 2010, CE Electric UK replaced its expiring £100 million unsecured credit facility with a £150 million unsecured credit facility expiring in March 2013. The £150 million credit facility has substantially the same covenant terms as the expired £100 million credit facility.

(9) Related Party Transactions

As of September 30, 2010 and December 31, 2009, Berkshire Hathaway and its affiliates held 11% mandatory redeemable preferred securities due from certain wholly-owned subsidiary trusts of MEHC of \$186 million and \$353 million, respectively. Interest expense on these securities totaled \$7 million and \$13 million for the three-month periods ended September 30, 2010 and 2009, respectively, and \$25 million and \$47 million for the nine-month periods ended September 30, 2010 and 2009, respectively. Accrued interest totaled \$4 million and \$8 million as of September 30, 2010 and December 31, 2009, respectively.

For the nine-month periods ended September 30, 2010 and 2009, the Company received net cash payments for income taxes from Berkshire Hathaway totaling \$132 million and \$178 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,	
	2010	2009	2010	2009
Pension:				
Service cost	\$ 8	\$ 9	\$ 22	\$ 26
Interest cost	25	29	78	85
Expected return on plan assets	(29)	(29)	(86)	(85)
Net amortization	3	1	10	1
Net periodic benefit cost	<u>\$ 7</u>	<u>\$ 10</u>	<u>\$ 24</u>	<u>\$ 27</u>
Other Postretirement:				
Service cost	\$ 2	\$ 2	\$ 7	\$ 6
Interest cost	10	12	31	33
Expected return on plan assets	(11)	(11)	(32)	(30)
Net amortization	5	3	11	9
Net periodic benefit cost	<u>\$ 6</u>	<u>\$ 6</u>	<u>\$ 17</u>	<u>\$ 18</u>

Employer contributions to the domestic pension and other postretirement benefit plans are expected to be \$143 million and \$27 million, respectively, during 2010. As of September 30, 2010, \$138 million and \$19 million of contributions had been made to the domestic pension and other postretirement benefit plans, respectively.

In March 2010, the President signed into law healthcare reform legislation that included provisions to eliminate the tax deductibility of other postretirement costs to the extent of retiree drug subsidies received from the federal government beginning after December 31, 2012. Accordingly, the Company increased deferred income tax liabilities and, consistent with the expectation that such additional income tax expense amounts are probable of inclusion in regulated rates, recorded a \$53 million increase to net regulatory assets.

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,	
	2010	2009	2010	2009
Service cost	\$ 5	\$ 3	\$ 12	\$ 9
Interest cost	22	22	66	62
Expected return on plan assets	(26)	(27)	(76)	(77)
Net amortization	7	4	22	11
Net periodic benefit cost	<u>\$ 8</u>	<u>\$ 2</u>	<u>\$ 24</u>	<u>\$ 5</u>

Employer contributions to the UK pension plan are expected to be £45 million during 2010. As of September 30, 2010, £34 million, or \$51 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,	
	2010	2009	2010	2009
Federal statutory income tax rate	35%	35%	35%	35%
Federal and state income tax credits	(14)	(8)	(11)	(9)
State income tax, net of federal income tax benefit	4	—	3	1
Change in United Kingdom corporate income tax rate	(6)	—	(2)	—
Tax free gain on sale of business	(4)	—	(1)	—
Effects of ratemaking	(4)	(1)	(3)	(1)
Tax effect of foreign income	(2)	1	(3)	(1)
Tax method change	—	(14)	(1)	(5)
CE Casecnan noncontrolling interest verdict	—	—	(2)	—
Other, net	1	(3)	—	—
Effective income tax rate	<u>10%</u>	<u>10%</u>	<u>15%</u>	<u>20%</u>

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 that the facilities were placed in-service.

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% to be 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 during the three- and nine-month periods ended September 30, 2010.

The Utilities changed the method by which they determine current income tax deductions for repairs on certain of their regulated utility assets (the "repairs deduction"), which results in current deductibility for certain costs that are capitalized for book purposes. The Utilities were allowed to retroactively apply the method change and take a deduction for prior-year costs on the tax return being prepared at the time of the change. A repairs deduction for MidAmerican Funding's regulated gas utility assets, which was computed for tax years 2004 and forward and deducted on the 2009 income tax return, resulted in the recognition of \$7 million of net tax benefits in earnings for the nine-month period ended September 30, 2010. Earnings for the three- and nine-month periods ended September 30, 2009 reflect \$55 million of net tax benefits recognized for a repairs deduction related to MidAmerican Funding's regulated electric utility assets, which was computed for tax years 1998 and forward and deducted on the 2008 income tax return. Iowa, MidAmerican Funding's largest jurisdiction for rate regulated operations, requires immediate income recognition of such temporary differences. The ongoing impact of the repairs deduction change, along with other items recognized currently in income tax expense as the result of ratemaking, is reflected in the effects of ratemaking line above.

(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. The Company is also involved in other kinds of legal actions, some of which assert or may assert claims or seek to impose fines, penalties and other costs in substantial amounts and are described below.

PacifiCorp

In February 2007, the Sierra Club and the Wyoming Outdoor Council filed a complaint against PacifiCorp in the federal district court in Cheyenne, Wyoming, alleging violations of the Wyoming state opacity standards at PacifiCorp's Jim Bridger generating facility in Wyoming. Under Wyoming state requirements, which are part of the Jim Bridger generating facility's Title V permit and are enforceable by private citizens under the federal Clean Air Act, a potential source of pollutants such as a coal-fired generating facility must meet minimum standards for opacity, which is a measurement of light that is obscured in the flue of a generating facility. The complaint alleged thousands of violations of asserted six-minute compliance periods and sought an injunction ordering the Jim Bridger generating facility's compliance with opacity limits, civil penalties of \$32,500 per day per violation and the plaintiffs' costs of litigation. In February 2010, PacifiCorp, the Sierra Club and the Wyoming Outdoor Council reached an agreement in principle to settle all outstanding claims in the action. The settlement was reviewed by the United States Environmental Protection Agency ("EPA") and approved by the court. This matter is now concluded and did not have a material impact on PacifiCorp's consolidated financial results.

CalEnergy Philippines

In February 2002, pursuant to the share ownership adjustment mechanism in the CE Casecan Water and Energy Company, Inc. ("CE Casecan") shareholder agreement, MEHC's indirect wholly owned subsidiary, CE Casecan Ltd., advised the minority shareholder of CE Casecan, LaPrairie Group Contractors (International) Ltd. ("LPG") that MEHC's indirect ownership interest in CE Casecan had increased to 100% effective from commencement of commercial operations. In 2002, LPG filed a complaint in the Superior Court of the State of California, City and County of San Francisco (the "Superior Court"), against CE Casecan Ltd. and MEHC. LPG's complaint, as amended, seeks compensatory and punitive damages arising out of CE Casecan Ltd.'s and MEHC's alleged improper calculation of the proforma financial projections and alleged improper settlement of the Philippine National Irrigation Administration arbitration. In January 2006, the Superior Court entered a judgment in favor of LPG against CE Casecan Ltd regarding the calculation of the proforma financial projections. Pursuant to the judgment, 15% of the distributions of CE Casecan were deposited into escrow plus interest at 9% per annum. The judgment was appealed, and as a result of the appellate decision, LPG retained ownership of 10% of the shares of CE Casecan, with the remaining 5% share to be transferred to CE Casecan Ltd. subject to certain buy-up rights under the shareholder agreement. The issues relating to the exercise of the buy-up right were decided by the Superior Court and in June 2009, LPG exercised its buy-up rights with respect to the remaining 5% ownership interest. In October 2009, the Superior Court issued a judgment declaring that after the buy up LPG was a 15% shareholder. The judgment was appealed in January 2010 and is expected to conclude in 2011. In July 2010, the Superior Court issued a decision denying the remainder of LPG's claims.

In July 2005, MEHC and CE Casecan Ltd. commenced an action against San Lorenzo Ruiz Builders and Developers Group, Inc. ("San Lorenzo") in the District Court of Douglas County, Nebraska (the "District Court"), seeking a declaratory judgment as to San Lorenzo's right to repurchase up to 15% of the shares in CE Casecan. In January 2006, San Lorenzo filed a counterclaim against MEHC and CE Casecan Ltd. seeking declaratory relief that it has effectively exercised its option to purchase up to 15% of the shares of CE Casecan, that it is the rightful owner of such shares and that it is due all dividends previously paid on such shares. In March 2010, after a two-week jury trial, the District Court declined to submit the claims and defenses in the case to the jury. Instead, the District Court issued a directed verdict in April 2010, which management believes is based in part on the January 2006 findings of the Superior Court in the California litigation involving LPG discussed above. The order finds that San Lorenzo was entitled to be a 15% shareholder of CE Casecan effective March 30, 2002 and is owed \$32 million as of March 31, 2010. The Superior Court subsequently issued an order in the California litigation which management believes contradicts the April 2010 order issued by the District Court. MEHC filed motions to vacate or modify the order of the District Court or to grant a new trial based on errors in the proceeding and in light of the Superior Court order in the California litigation based on the same facts. The District Court denied the motions to vacate and modify its order, and any final ruling is expected to be appealed.

As a result of the court's ruling, the Company established a \$48 million noncontrolling interest attributable to San Lorenzo in CE Casecan. The noncontrolling interest established consisted of (1) 15% of CE Casecan's equity as of March 30, 2002 totaling \$17 million; (2) an \$83 million charge to net income attributable to noncontrolling interests representing 15% of CE Casecan's earnings since March 30, 2002; and (3) a \$52 million reduction to San Lorenzo's noncontrolling interest for 15% of CE Casecan's dividends paid since March 30, 2002, which is recorded in other current liabilities on the Consolidated Balance Sheet. The court's ruling resulted in a \$59 million after-tax charge to net income attributable to MEHC in March 2010. Depending on the ultimate outcome of the litigation, adjustments to this estimate may be necessary.

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, climate change, 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.

Accrued Environmental Costs

The Company is fully or partly responsible for environmental remediation at various contaminated sites, including sites that are or were part of the Company's operations and sites owned by third parties. The Company accrues environmental remediation expenses when the expenses are believed to be probable and can be reasonably estimated. The quantification of environmental exposures is based on many factors, including changing laws and regulations, advancements in environmental technologies, the quality of available site-specific information, site investigation results, expected remediation or settlement timelines, the Company's proportionate responsibility, contractual indemnities and coverage provided by insurance policies. The liability recorded as of September 30, 2010 and December 31, 2009 was \$18 million and \$21 million, respectively, and is included in other current liabilities and other long-term liabilities on the Consolidated Balance Sheets. Environmental remediation liabilities that separately result from the normal operation of long-lived assets and that are legal obligations associated with the retirement of those assets are separately accounted for as asset retirement obligations.

Hydroelectric Relicensing

PacifiCorp's hydroelectric portfolio consists of 46 generating facilities with an aggregate facility net owned capacity of 1,157 megawatts ("MW"). The FERC regulates 98% of the net capacity of this portfolio through 16 individual licenses, which typically 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 2004, PacifiCorp filed with the FERC a final application for a new license to operate the 170-MW Klamath hydroelectric system in anticipation of the March 2006 expiration of the existing license. PacifiCorp is currently operating under an annual license issued by the FERC and expects to continue operating under annual licenses until the relicensing process is complete or the system's four mainstem dams are removed.

As part of the relicensing process, the FERC is required to perform an environmental review and in November 2007, the FERC issued its final environmental impact statement. The United States Fish and Wildlife Service and the National Marine Fisheries Service issued final biological opinions in December 2007 analyzing the Klamath hydroelectric system's impact on endangered species under a new FERC license consistent with the FERC staff's recommended license alternative and terms and conditions issued by the United States Departments of the Interior and Commerce. These terms and conditions include construction of upstream and downstream fish passage facilities at the Klamath hydroelectric system's four mainstem dams. Prior to the FERC issuing a final license, PacifiCorp is required to obtain water quality certifications from Oregon and California. PacifiCorp currently has water quality applications pending in Oregon and California; however, Oregon issued a letter in March 2010, holding the certification process in abeyance during the United States Secretary of the Interior's public interest determination on dam removal, and California issued a resolution in October 2010, holding the certification process in abeyance until May 2011.

In November 2008, PacifiCorp signed a non-binding agreement in principle ("AIP") that laid out a framework for the disposition of PacifiCorp's Klamath hydroelectric system relicensing process, including a path toward potential dam transfer and removal by an entity other than PacifiCorp no earlier than 2020. Subsequent to release of the AIP, negotiations between the parties continued with an expanded group of stakeholders. The parties to the Klamath Hydroelectric Settlement Agreement ("KHSA"), which include 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 KHSA in February 2010. PacifiCorp expects that federal legislation will be introduced in the United States Congress in 2011 to endorse and enact provisions of the KHSA.

Under the terms of the KHSA, the United States Departments of the Interior and Commerce will conduct scientific and engineering studies and consult with state, local and tribal governments and other stakeholders, as appropriate, to determine by March 31, 2012 whether removal of the Klamath hydroelectric system's four mainstem dams will advance restoration of the salmonid fisheries of the Klamath Basin and is in the public interest. This determination will be made by the United States Secretary of the Interior. 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. 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. If PacifiCorp's contribution to dam removal costs exceeds \$200 million or if the State of California is unable to raise the funds necessary for dam removal costs, sufficient funds would need to be obtained elsewhere in order for the KHSA and dam removal to proceed.

Actual removal of a facility would occur only after all permits for removal are obtained and the facility and associated land are transferred to a dam removal entity. Prior to potential removal of a facility, the facility will generally continue to operate as it does currently. However, PacifiCorp is responsible for implementing interim measures to provide additional resource protections, water quality improvements, habitat enhancement for aquatic species and increased funding for hatchery operations in the Klamath River Basin.

In July 2009, Oregon's governor signed a bill authorizing PacifiCorp to collect surcharges from its Oregon customers for Oregon's share of the customer contribution for the cost of removing the Klamath hydroelectric system's four mainstem dams. In March 2010, PacifiCorp filed with the OPUC to begin collecting the surcharge from Oregon customers, as of that date, subject to refund based on the OPUC's determination that the surcharges result in rates that are fair, just and reasonable. Also, in March 2010, PacifiCorp filed with the California Public Utilities Commission ("CPUC") to collect a surcharge from PacifiCorp's California customers beginning January 1, 2011. The proceeds from the surcharges will be deposited in trust accounts to be established by each of the respective utility commissions. In September 2010, the OPUC issued an order approving dam removal surcharges for Oregon customers. The CPUC is expected to issue an order on PacifiCorp's California surcharge filing in April 2011.

As of September 30, 2010 and December 31, 2009, PacifiCorp had \$73 million and \$67 million, respectively, in costs related to the relicensing of the Klamath hydroelectric system included in construction in progress and reflected in property, plant and equipment, net on the Consolidated Balance Sheets. Recovery of relicensing costs is anticipated through traditional rate proceedings. The all-party settlement proposed in the Oregon general rate case recommended recovery of relicensing costs effective January 1, 2011. As of September 30, 2010, PacifiCorp's Klamath hydroelectric system generating facilities had a net book value of \$60 million with an average remaining depreciable life of 36 years. In August 2010, PacifiCorp received an order from the OPUC approving a change to depreciation rates for certain of the Klamath hydroelectric system generating facilities. The depreciation rate change will be effective January 1, 2011 and will allow for full depreciation of the assets by December 31, 2019. PacifiCorp has made a similar filing in California and plans to include a similar request in upcoming rate cases in the rest of the states comprising its service territory.

Purchase Obligations

In September 2010, PacifiCorp amended an existing coal supply agreement and entered into a new coal supply agreement, each establishing annual minimum purchases of coal to supply one of PacifiCorp's coal-fired generating facilities. Prior to the amendment, the existing agreement did not require a minimum level of purchases. The coal supply agreements result in minimum future purchases for the years ending December 31 of approximately \$90 million in 2011, \$93 million in 2012, \$99 million in 2013, \$101 million in 2014, \$109 million in 2015 and \$731 million thereafter.

(13) MEHC Shareholders' Equity

In March 2010, MEHC purchased 250,000 shares of common stock for \$225 per share, or \$56 million, from Mr. Scott (along with family members and related entities). In March 2009, 703,329 common stock options were exercised having an exercise price of \$35.05 per share, or \$25 million. Also in March 2009, MEHC purchased the shares issued from the options exercised for \$148 million. As a result, the Company recognized \$125 million of stock-based compensation expense, including the Company's share of payroll taxes, for the nine-month period ended September 30, 2009, which is included in operating expense on the Consolidated Statement of Operations.

(14) Components of Accumulated Other Comprehensive Income, Net

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

	As of	
	September 30, 2010	December 31, 2009
Unrecognized amounts on retirement benefits, net of tax of \$(183) and \$(201)	\$ (492)	\$ (515)
Foreign currency translation adjustment	(277)	(191)
Fair value adjustment on cash flow hedges, net of tax of \$(12) and \$-	(18)	—
Unrealized gains on marketable securities, net of tax of \$620 and \$693	930	1,041
Total accumulated other comprehensive income attributable to MEHC, net	\$ 143	\$ 335

(15) Sale of Business

In September 2010, the Company sold its interest in CE Gas (Australia) Limited, which had previously been reported as part of the CE Electric UK reportable segment, for net proceeds of \$59 million. The Company recognized a tax free gain of \$45 million during the three- and nine-month periods ended September 30, 2010 related to this transaction, which is included in operating expense on the Consolidated Statements of Operations. The amounts previously reported in operating revenue and income before income tax expense associated with CE Gas (Australia) Limited are not material to the Company's consolidated financial results.

(16) 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 CE Electric UK, 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,	
	2010	2009	2010	2009
Operating revenue:				
PacifiCorp	\$ 1,165	\$ 1,146	\$ 3,323	\$ 3,278
MidAmerican Funding	933	812	2,895	2,711
Northern Natural Gas	116	116	423	477
Kern River	90	90	264	283
CE Electric UK	184	214	582	604
CalEnergy Philippines	25	51	69	107
CalEnergy U.S.	9	9	25	24
HomeServices	253	312	793	764
Corporate/other ⁽¹⁾	(12)	(9)	(44)	(36)
Total operating revenue	\$ 2,763	\$ 2,741	\$ 8,330	\$ 8,212
Depreciation and amortization:				
PacifiCorp	\$ 140	\$ 139	\$ 422	\$ 414
MidAmerican Funding	86	85	258	251
Northern Natural Gas	16	16	48	47
Kern River	27	24	81	72
CE Electric UK	43	44	119	121
CalEnergy Philippines	6	6	17	17
CalEnergy U.S.	2	2	6	6
HomeServices	4	5	11	13
Corporate/other ⁽¹⁾	(4)	(3)	(12)	(12)
Total depreciation and amortization	\$ 320	\$ 318	\$ 950	\$ 929
Operating income:				
PacifiCorp	\$ 284	\$ 299	\$ 815	\$ 796
MidAmerican Funding	148	123	364	363
Northern Natural Gas	31	37	175	238
Kern River	51	54	148	174
CE Electric UK	136	109	348	306
CalEnergy Philippines	17	42	45	82
CalEnergy U.S.	5	4	13	12
HomeServices	3	18	20	16
Corporate/other ⁽¹⁾	(31)	(25)	(65)	(165)
Total operating income	644	661	1,863	1,822
Interest expense	(309)	(316)	(923)	(957)
Capitalized interest	14	12	42	30
Interest and dividend income	4	8	24	36
Other, net	33	41	89	119
Total income before income tax expense and equity income	\$ 386	\$ 406	\$ 1,095	\$ 1,050

	Three-Month Periods Ended September 30,		Nine-Month Periods Ended September 30,	
	2010	2009	2010	2009
Interest expense:				
PacifiCorp	\$ 101	\$ 102	\$ 303	\$ 310
MidAmerican Funding	48	48	144	148
Northern Natural Gas	15	15	45	45
Kern River	12	14	38	42
CE Electric UK	37	39	109	109
CalEnergy Philippines	2	1	4	3
CalEnergy U.S.	4	4	12	12
Corporate/other ⁽¹⁾	90	93	268	288
Total interest expense	<u>\$ 309</u>	<u>\$ 316</u>	<u>\$ 923</u>	<u>\$ 957</u>

	As of	
	September 30, 2010	December 31, 2009
Total assets:		
PacifiCorp	\$ 21,038	\$ 20,244
MidAmerican Funding	10,766	10,732
Northern Natural Gas	2,698	2,657
Kern River	1,932	1,875
CE Electric UK	5,463	5,622
CalEnergy Philippines	405	463
CalEnergy U.S.	582	569
HomeServices	675	657
Corporate/other ⁽¹⁾	1,964	1,865
Total assets	<u>\$ 45,523</u>	<u>\$ 44,684</u>

- (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, 2010 (in millions):

	PacifiCorp	MidAmerican Funding	Northern Natural Gas	Kern River	CE Electric UK	CalEnergy U.S.	Home- Services	Total
Balance, December 31, 2009	\$ 1,126	\$ 2,102	\$ 223	\$ 34	\$ 1,130	\$ 71	\$ 392	\$ 5,078
Foreign currency translation	—	—	—	—	(23)	—	—	(23)
Other	—	—	(20)	—	—	—	1	(19)
Balance, September 30, 2010	<u>\$ 1,126</u>	<u>\$ 2,102</u>	<u>\$ 203</u>	<u>\$ 34</u>	<u>\$ 1,107</u>	<u>\$ 71</u>	<u>\$ 393</u>	<u>\$ 5,036</u>

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 MidAmerican Energy Holdings Company ("MEHC") and its subsidiaries (collectively, the "Company") during the periods included herein. Explanations include management's best estimate of the impact 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 is 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"), CE Electric UK Funding Company ("CE Electric UK") (which primarily consists of Northern Electric Distribution Limited ("Northern Electric") and Yorkshire Electricity Distribution plc ("Yorkshire Electricity")), CalEnergy Philippines (which owns a majority interest in the Casecan 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, MEHC 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.

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 "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 Company's control and could cause actual results to differ materially from those expressed or implied by the Company's forward-looking statements. These factors include, among others:

- general economic, political and business conditions in the jurisdictions in which the Company's facilities operate;
- changes in federal, state and local governmental, legislative or regulatory requirements affecting the Company or the electric or gas utility, pipeline or power generation industries;
- changes in, and compliance with, environmental laws, regulations, decisions and policies that could, among other items, increase operating and capital costs, reduce plant output, accelerate plant retirements or delay plant construction;
- the outcome of general rate cases and other proceedings conducted by regulatory commissions or other governmental and legal bodies;
- changes in economic, industry or weather conditions, as well as demographic trends, that could affect customer growth and usage or supply of electricity and gas or the Company's ability to obtain long-term contracts with customers and suppliers;
- a high degree of variance between actual and forecasted load and prices that could impact the hedging strategy and costs to balance electricity and load supply;
- 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 generation 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;
- performance of the Company's generating facilities, including unscheduled outages or repairs;
- 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;
- 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 that could affect brokerage 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 impact of new accounting guidance or changes in current accounting estimates and assumptions on consolidated financial results;
- the Company's ability to successfully integrate future acquired operations into its business;
- other risks or unforeseen events, including litigation, wars, the effects of 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 ("SEC") 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 SEC, 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.

Results of Operations for the Third Quarter and First Nine Months of 2010 and 2009

Overview

Net income attributable to MEHC for the third quarter of 2010 was \$364 million, a decrease of \$12 million, or 3%, compared to 2009. Lower net income at PacifiCorp, MidAmerican Funding, CalEnergy Philippines and HomeServices was partially offset by higher net income at CE Electric UK. PacifiCorp's net income decreased due to the favorable settlement of certain tax contingencies in 2009 and higher operating expense and depreciation and amortization associated with recent plant placed in-service, partially offset by higher production tax credits in 2010 and slightly higher margins. Net income at MidAmerican Funding decreased primarily due to \$55 million of income tax benefits recognized in 2009 for a change in the tax accounting method determining current income tax deductions for certain electric asset repairs, partially offset by higher electric margins primarily due to warmer weather and other income tax benefits in 2010. CalEnergy Philippines' net income decreased due to lower rainfall and related lower revenue earned in 2010 at the Casecnan project. Net income at HomeServices decreased due to lower operating revenue, partially offset by lower commissions and operating expenses. CE Electric UK's net income increased due to a \$45 million after-tax gain on the sale of CE Gas (Australia) Limited and the recognition of deferred income tax benefits totaling \$25 million upon the enactment of the reduction in the United Kingdom corporate income tax rate from 28% to 27%, partially offset by lower allowed distribution revenue and the stronger United States dollar.

Net income attributable to MEHC for the first nine months of 2010 was \$859 million, a decrease of \$5 million, or 1%, compared to 2009. Lower net income at MidAmerican Funding, Northern Natural Gas, Kern River, CalEnergy Philippines and CalEnergy U.S. was partially offset by higher net income at PacifiCorp and CE Electric UK. Net income decreased at MidAmerican Funding primarily due to \$55 million of income tax benefits recognized in 2009 for a change in the tax accounting method determining current income tax deductions for certain electric asset repairs and higher storm restoration costs, partially offset by additional production tax credits. Net income at Northern Natural Gas and Kern River was lower as a result of lower revenue from less favorable market conditions. CalEnergy Philippines' net income decreased due to lower rainfall and related lower revenue earned in 2010 at the Casecnan project. CalEnergy U.S.'s net income decreased due to the expiration of a favorable power purchase contract in the second quarter of 2009. PacifiCorp's net income was higher due to higher prices approved by regulators, higher sales of renewable energy credits, higher allowance for funds used during construction ("AFUDC") and a lower effective income tax rate, partially offset by lower wholesale and other revenue, higher operating expense and depreciation and amortization associated with recent plant placed in-service, the benefits in 2009 from Oregon Senate Bill 408 ("SB 408") and the favorable settlement of certain tax contingencies in 2009. Net income at CE Electric UK increased due to the after-tax gain on the sale of CE Gas (Australia) Limited and the recognition of deferred income tax benefits for the reduction in the United Kingdom corporate income tax rate. The results for the first nine months of 2009 also included an after-tax gain on the Constellation Energy Group, Inc. ("Constellation Energy") common stock investment of \$22 million and an after-tax stock-based compensation charge of \$75 million as a result of the purchase of shares of common stock that were issued upon the exercise of stock options. The results for the first nine months of 2010 included an after-tax charge of \$64 million related to the CE Casecnan noncontrolling interest verdict and ongoing noncontrolling interest expense.

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				
	2010	2009	Change		2010	2009	Change		
Operating revenue:									
PacifiCorp	\$ 1,165	\$ 1,146	\$ 19	2%	\$ 3,323	\$ 3,278	\$ 45	1%	
MidAmerican Funding	933	812	121	15	2,895	2,711	184	7	
Northern Natural Gas	116	116	—	—	423	477	(54)	(11)	
Kern River	90	90	—	—	264	283	(19)	(7)	
CE Electric UK	184	214	(30)	(14)	582	604	(22)	(4)	
CalEnergy Philippines	25	51	(26)	(51)	69	107	(38)	(36)	
CalEnergy U.S.	9	9	—	—	25	24	1	4	
HomeServices	253	312	(59)	(19)	793	764	29	4	
Corporate/other	(12)	(9)	(3)	(33)	(44)	(36)	(8)	(22)	
Total operating revenue	<u>\$ 2,763</u>	<u>\$ 2,741</u>	<u>\$ 22</u>	1	<u>\$ 8,330</u>	<u>\$ 8,212</u>	<u>\$ 118</u>	1	
Operating income:									
PacifiCorp	\$ 284	\$ 299	\$ (15)	(5)%	\$ 815	\$ 796	\$ 19	2%	
MidAmerican Funding	148	123	25	20	364	363	1	—	
Northern Natural Gas	31	37	(6)	(16)	175	238	(63)	(26)	
Kern River	51	54	(3)	(6)	148	174	(26)	(15)	
CE Electric UK	136	109	27	25	348	306	42	14	
CalEnergy Philippines	17	42	(25)	(60)	45	82	(37)	(45)	
CalEnergy U.S.	5	4	1	25	13	12	1	8	
HomeServices	3	18	(15)	(83)	20	16	4	25	
Corporate/other	(31)	(25)	(6)	(24)	(65)	(165)	100	61	
Total operating income	<u>\$ 644</u>	<u>\$ 661</u>	<u>\$ (17)</u>	(3)	<u>\$ 1,863</u>	<u>\$ 1,822</u>	<u>\$ 41</u>	2	

PacifiCorp

Operating revenue increased \$19 million for the third quarter of 2010 compared to 2009 due to higher retail revenue of \$67 million, partially offset by a decrease in wholesale and other revenue of \$55 million. The increase in retail revenue was due to an increase in prices approved by regulators, higher demand-side management revenue, which is offset by higher operating expenses, and a 2% increase in volumes. Retail volumes increased as a result of higher customer usage in PacifiCorp's eastern service territory, partially offset by lower residential and commercial usage in PacifiCorp's western service territory primarily due to the impacts of unfavorable weather. The decrease in wholesale and other revenue was due to a 19% decrease in wholesale volumes as a result of lower thermal generation, a 15% decrease in average wholesale prices and the impact of deconsolidating PacifiCorp's coal mining joint venture, Bridger Coal Company ("Bridger Coal"), as a result of adopting authoritative guidance requiring equity method accounting treatment of the operations effective January 1, 2010. The lower revenue due to deconsolidating Bridger Coal is largely offset by lower operating expense and depreciation and amortization.

Operating income decreased \$15 million for the third quarter of 2010 compared to 2009. The higher revenue was largely offset by higher energy costs. Energy costs increased due to higher purchased electricity as a result of lower thermal generation, higher coal prices and higher transmission costs, partially offset by lower fuel costs on lower thermal generation and the effects of regulatory cost recovery adjustment mechanisms for net power costs of \$6 million. Operating expense and depreciation and amortization both increased due to recent plant placed in-service.

Operating revenue increased \$45 million for the first nine months of 2010 compared to 2009 due to higher retail revenue of \$143 million and an increase in the sale of renewable energy credits totaling \$49 million, partially offset by a decrease in wholesale and other revenue of \$150 million. The increase in retail revenue was due to an increase in prices approved by regulators, higher demand-side management revenue, which is offset by higher operating expenses, and a 1% increase in volumes, partially offset by lower revenue related to SB 408 of \$10 million. The decrease in wholesale and other revenue was due to a 8% decrease in wholesale volumes, a 15% decrease in average wholesale prices and the impact of deconsolidating Bridger Coal. The lower revenue due to deconsolidating Bridger Coal is largely offset by lower operating expense and depreciation and amortization.

Operating income increased \$19 million for the first nine months of 2010 compared to 2009 due to the higher operating revenue and lower energy costs of \$17 million, partially offset by higher costs associated with recent plant placed in-service and increased plant overhauls. Energy costs decreased due to a decrease in the average cost of purchased electricity and the effects of regulatory cost recovery adjustment mechanisms for net power costs of \$26 million, partially offset by higher transmission costs of \$17 million and unfavorable changes in the fair value of energy purchase contracts accounted for as derivatives.

MidAmerican Funding

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

	Third Quarter				First Nine Months				
	2010	2009	Change		2010	2009	Change		
Operating revenue:									
Regulated electric	\$ 505	\$ 451	\$ 54	12%	\$ 1,361	\$ 1,286	\$ 75	6 %	
Regulated natural gas	110	85	25	29	625	591	34	6	
Nonregulated and other	318	276	42	15	909	834	75	9	
Total operating revenue	<u>\$ 933</u>	<u>\$ 812</u>	<u>\$ 121</u>	15	<u>\$ 2,895</u>	<u>\$ 2,711</u>	<u>\$ 184</u>	7	
Operating income:									
Regulated electric	\$ 130	\$ 112	18	16%	266	272	(6)	(2)%	
Regulated natural gas	(3)	(4)	1	25	43	43	—	—	
Nonregulated and other	21	15	6	40	55	48	7	15	
Total operating income	<u>\$ 148</u>	<u>\$ 123</u>	<u>\$ 25</u>	20	<u>\$ 364</u>	<u>\$ 363</u>	<u>\$ 1</u>	—	

Regulated electric operating revenue increased \$54 million for the third quarter of 2010 compared to 2009. Retail revenue increased \$44 million on higher volumes of 12% primarily due to higher customer usage as a result of the impacts of favorable weather. Wholesale and other revenue increased \$10 million due to higher average wholesale prices and volumes. Generation increased 15% resulting from higher availability primarily due to joining the Midwest Independent Transmission System Operation, Inc. ("MISO") in September 2009.

Regulated electric operating income increased \$18 million for the third quarter of 2010 compared to 2009. The higher operating revenue was partially offset by higher energy costs of \$32 million and higher storm restoration costs. Energy costs increased due to greater coal-fired and natural gas-fired generation as a result of higher volumes and higher fuel prices.

Regulated natural gas operating revenue increased \$25 million for the third quarter of 2010 compared to 2009 due to an increase in the average per-unit cost of gas sold, which was passed on to customers and resulted in higher cost of sales, and higher wholesale sales volumes. Regulated natural gas operating income increased \$1 million for the third quarter of 2010 compared to 2009.

Nonregulated and other operating revenue increased \$42 million for the third quarter of 2010 compared to 2009 due to a 13% increase in electric retail volumes and higher gas revenue resulting from an increase in prices, partially offset by a 3% decrease in electric retail rates and lower gas volumes. Nonregulated and other operating income increased \$6 million for the third quarter of 2010 compared to 2009 due to higher electric margins.

Regulated electric operating revenue increased \$75 million for the first nine months of 2010 compared to 2009. Retail revenue increased \$78 million on higher volumes of 8% primarily due to higher customer usage, including the impacts of favorable weather, and customer growth. Wholesale and other revenue decreased \$3 million due to lower average wholesale sales prices, partially offset by higher volumes due to a 13% increase in generation resulting from higher availability primarily due to joining the MISO.

Regulated electric operating income decreased \$6 million for the first nine months of 2010 compared to 2009. Higher energy costs of \$68 million, higher depreciation and amortization totaling \$6 million and higher operating expenses totaling \$7 million were partially offset by the higher operating revenue. Energy costs increased due to greater thermal generation as a result of higher volumes and higher fuel prices. Operating expenses increased primarily due to higher maintenance costs as a result of storm damage totaling \$15 million, partially offset by lower general maintenance and health care costs.

Regulated natural gas operating revenue increased \$34 million for the first nine months of 2010 compared to 2009 due to an increase in the average per-unit cost of gas sold, which was passed on to customers and resulted in higher cost of sales, partially offset by lower wholesale sales volumes. Regulated natural gas operating income was flat for the first nine months of 2010 compared to 2009.

Nonregulated and other operating revenue increased \$75 million for the first nine months of 2010 compared to 2009 due to a 15% increase in electric retail volumes and higher gas revenue resulting from an increase in prices, partially offset by a 4% decrease in electric retail rates and lower gas volumes. Nonregulated and other operating income increased \$7 million for the first nine months of 2010 compared to 2009 primarily due to higher electric margins.

Northern Natural Gas

Operating revenue was unchanged for the third quarter of 2010 compared to 2009 as higher sales of gas and condensate liquids were offset by lower storage revenue. Operating income decreased \$6 million for the third quarter of 2010 compared to 2009 due to the lower storage revenue and losses recognized on derivative gas purchase contracts.

Operating revenue decreased \$54 million for the first nine months of 2010 compared to 2009 primarily due to lower transportation revenue of \$46 million and lower storage revenue of \$13 million, partially offset by higher sales of gas and condensate liquids. Transportation revenue decreased due to lower transportation volumes, principally in the field area, caused by less favorable economic conditions and lower natural gas price spreads. Operating income decreased \$63 million for the first nine months of 2010 compared to 2009 primarily due to the lower transportation and storage revenue.

Kern River

Operating revenue was unchanged for the third quarter of 2010 compared to 2009 as revenue from the 2010 Expansion project that was placed in service in April 2010 was offset by lower rates as a result of the Federal Energy Regulatory Commission ("FERC") order received in December 2009. Operating income decreased \$3 million for the third quarter of 2010 compared to 2009 due to higher depreciation and amortization as a result of higher levelized depreciation and placing the 2010 Expansion project in service.

Operating revenue decreased \$19 million for the first nine months of 2010 compared to 2009 due to lower natural gas price spreads and volumes and lower rates as a result of the FERC order received in December 2009, partially offset by higher revenue from the 2010 Expansion project being placed in service. Operating income decreased \$26 million for the first nine months of 2010 compared to 2009 due to the lower operating revenue and higher depreciation and amortization totaling \$8 million as a result of higher levelized depreciation and placing the 2010 Expansion project in service.

CE Electric UK

Operating revenue decreased \$30 million for the third quarter of 2010 compared to 2009. The decrease was due to the stronger United States dollar totaling \$11 million, lower contracting revenue of \$10 million, lower gas production of \$5 million and lower distribution revenue of \$4 million. Distribution revenue decreased primarily due to lower allowed revenue from certain regulatory provisions totaling \$28 million, partially offset by higher rates implemented April 1, 2010 related to the Distribution Price Control Review. Operating income increased \$27 million for the third quarter of 2010 compared to 2009 primarily due to a pre-tax gain of \$45 million recognized on the sale of CE Gas (Australia) Limited, partially offset by the stronger United States dollar totaling \$8 million, the lower distribution revenue and the lower gas production.

Operating revenue decreased \$22 million for the first nine months of 2010 compared to 2009. The decrease was due to lower contracting revenue of \$15 million and lower gas production of \$12 million, partially offset by higher distribution revenue of \$8 million. Distribution revenue increased due to higher rates implemented April 1, 2010 related to the Distribution Price Control Review, partially offset by lower allowed revenue from certain regulatory provisions totaling \$53 million. Operating income increased \$42 million for the first nine months of 2010 compared to 2009 primarily due to a \$45 million pre-tax gain recognized on the sale of CE Gas (Australia) Limited and the higher distribution revenue, partially offset by the lower gas production.

CalEnergy Philippines

Operating revenue decreased \$26 million for the third quarter and \$38 million for the first nine months of 2010 compared to 2009 due to lower than normal rainfall in 2010 and above normal rainfall in 2009 at the Casecnan project, which resulted in lower variable energy and water delivery fees earned in 2010. Operating income decreased \$25 million for the third quarter and \$37 million for the first nine months of 2010 compared to 2009 due to the lower operating revenue.

HomeServices

Operating revenue decreased \$59 million for the third quarter of 2010 compared to 2009 primarily due to a 27% decrease in closed brokerage units as the first-time home buyer tax credit expired in June 2010, partially offset by higher average home sales prices. Operating income decreased \$15 million for the third quarter of 2010 compared to 2009 primarily due to the lower operating revenue, partially offset by lower commissions and operating expenses.

Operating revenue increased \$29 million for the first nine months of 2010 compared to 2009 due to higher average home sales prices. Operating income increased \$4 million for the first nine months of 2010 compared to 2009 primarily due to the higher operating revenue and lower operating expenses, partially offset by higher commissions.

Corporate/other

Operating income increased \$100 million for the first nine months of 2010 compared to 2009 due to \$125 million of stock-based compensation expense in 2009 as a result of the purchase of common stock issued by MEHC upon the exercise of the last remaining stock options that had been granted to certain members of management at the time of Berkshire Hathaway Inc.'s ("Berkshire Hathaway") acquisition of MEHC in 2000.

Consolidated Other Income and Expense Items

Interest Expense

Interest expense is summarized as follows (in millions):

	Third Quarter				First Nine Months			
	2010	2009	Change		2010	2009	Change	
Subsidiary debt	\$ 213	\$ 212	\$ 1	—%	\$ 633	\$ 644	\$ (11)	(2)%
MEHC senior debt and other	82	85	(3)	(4)	247	249	(2)	(1)
MEHC subordinated debt -								
Berkshire Hathaway	7	13	(6)	(46)	25	47	(22)	(47)
MEHC subordinated debt - other	7	6	1	17	18	17	1	6
Total interest expense	<u>\$ 309</u>	<u>\$ 316</u>	<u>\$ (7)</u>	(2)	<u>\$ 923</u>	<u>\$ 957</u>	<u>\$ (34)</u>	(4)

Interest expense decreased \$7 million for the third quarter and \$34 million for the first nine months of 2010 compared to 2009 due to scheduled maturities, principal repayments and lower interest rates on variable rate debt, partially offset by the \$250 million debt issuance in July 2009 at MEHC.

Capitalized Interest

Capitalized interest increased \$12 million for the first nine months of 2010 compared to 2009 due to higher construction in progress at PacifiCorp.

Interest and Dividend Income

Interest and dividend income decreased \$12 million for the first nine months of 2010 compared to 2009 primarily due to interest associated with SB 408 refunds received in 2009 at PacifiCorp and income earned in 2009 related to the Constellation Energy investments, partially offset by a dividend received during the second quarter of 2010 from the BYD Company Limited common stock investment totaling \$11 million.

Other, Net

Other, net decreased \$8 million for the third quarter and \$30 million for the first nine months of 2010 compared to 2009. The decrease for the third quarter of 2010 compared to 2009 was primarily due to a gain recognized on an acquisition by HomeServices in 2009. Additionally, the first nine months of 2010 compared to 2009 decreased due to a \$37 million pre-tax gain on the Constellation Energy common stock investment in 2009, partially offset by higher allowance for equity funds used during construction at PacifiCorp in 2010.

Income Tax Expense

Income tax expense decreased \$1 million for the third quarter and \$46 million for the first nine months of 2010 compared to 2009. The effective tax rates were 10% for both the third quarter of 2010 and 2009, and 15% and 20% for the first nine months of 2010 and 2009, respectively. The results for the third quarter and first nine months of 2010 included production tax credits of \$48 million and \$113 million, respectively, deferred income tax benefits totaling \$25 million upon the enactment of the reduction in the United Kingdom corporate income tax rate from 28% to 27% and a non-taxable gain on the sale of CE Gas (Australia) Limited. The results for the third quarter and first nine months of 2009 included production tax credits of \$33 million and \$88 million, respectively, and accelerated income tax benefits of \$55 million for repairs deductions. The benefits were realized as MidAmerican Energy changed the method by which it determines current income tax deductions for repairs on certain of its regulated utility assets, which results in current deductibility for costs that are capitalized for book purposes. Iowa, MidAmerican Energy's largest jurisdiction for rate-regulated operations, requires immediate income recognition of such temporary differences. Additionally, the effective tax rates for the third quarter and first nine months of 2010 compared to 2009 were impacted by higher benefits from the effects of ratemaking and lower taxes on foreign income.

Equity Income

Equity income decreased \$20 million for the first nine months of 2010 compared to 2009 due to lower equity earnings at CE Generation, LLC, primarily due to the expiration of a favorable power purchase contract in the second quarter of 2009 at the Saranac project, and at HomeServices related to lower refinance activity in its mortgage business.

Net Income Attributable to Noncontrolling Interests

Net income attributable to noncontrolling interests increased \$76 million for the first nine months of 2010 compared to 2009 due to an \$83 million charge related to the CE Casecanan 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, the assets of each subsidiary may be pledged or encumbered to support or otherwise provide the security for its own subsidiary debt. It should not be assumed that any asset of any subsidiary of MEHC's will be available to satisfy the obligations of MEHC or any of its other subsidiaries' obligations. However, unrestricted cash or other assets which 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, 2010, the Company's total net liquidity available was \$6.438 billion. The components of total net liquidity available are as follows (in millions):

	<u>MEHC</u>	<u>PacifiCorp</u>	<u>MidAmerican Funding</u>	<u>CE Electric UK</u>	<u>Other</u>	<u>Total⁽¹⁾</u>
Cash and cash equivalents	\$ 10	\$ 32	\$ 201	\$ 24	\$ 254	\$ 521
Credit facilities	\$ 585	\$ 1,395	\$ 654	\$ 660	\$ 125	\$ 3,419
Less:						
Short-term borrowings and issuances of commercial paper	(192)	(34)	—	—	—	(226)
Tax-exempt bond support, letters of credit and EIB borrowings	(40)	(304)	(195)	(237)	—	(776)
Net credit facilities	\$ 353	\$ 1,057	\$ 459	\$ 423	\$ 125	\$ 2,417
Net liquidity before Berkshire						
Equity Commitment	\$ 363	\$ 1,089	\$ 660	\$ 447	\$ 379	\$ 2,938
Berkshire Equity Commitment ⁽²⁾	3,500					3,500
Total net liquidity	\$ 3,863					\$ 6,438
Unsecured revolving credit facilities:						
Maturity date ⁽³⁾	<u>2013</u>	<u>2012-2013</u>	<u>2011, 2013</u>	<u>2013</u>	<u>2010</u>	
Largest single bank commitment as a % of total revolving credit facilities ⁽⁴⁾	<u>17%</u>	<u>15%</u>	<u>23%</u>	<u>33%</u>	<u>36%</u>	

- (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) In March 2006, MEHC and Berkshire Hathaway entered into the Berkshire Equity Commitment pursuant to which Berkshire Hathaway has agreed to purchase up to \$3.5 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. In March 2010, MEHC and Berkshire Hathaway amended the Berkshire Equity Commitment extending the term from February 28, 2011 to February 28, 2014 and reducing the Maximum Equity Amount, as defined in the agreement, from \$3.5 billion to \$2.0 billion effective March 1, 2011.
- (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, 2009.
- (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, 2010 and 2009 were \$2.080 billion and \$2.983 billion, respectively. The decrease was mainly due to \$140 million of net cash flows in 2009 related to the Constellation Energy transaction, which is comprised of \$536 million of proceeds received from the sale of Constellation Energy common stock and \$396 million of income taxes paid on gains recognized on the termination of the Constellation Energy merger agreement in December 2008 and the sale of common stock in 2009, lower income tax receipts of \$490 million, changes in collateral posted for derivative contracts and higher contributions to pension and other postretirement benefit plans. Income tax receipts were lower primarily due to repairs deductions and the timing of bonus depreciation received in 2009.

In September 2010, the President signed the Small Business Jobs Act into law, extending retroactively to January 1, 2010, the 50% depreciation bonus for qualifying property purchased and placed in service in 2010. As a result of the new law, the Company's third quarter tax provision reflected bonus depreciation on qualifying assets placed in service during 2010. Accordingly, the Company's receivable for income taxes increased to \$440 million as of September 30, 2010.

Investing Activities

Net cash flows from investing activities for the nine-month periods ended September 30, 2010 and 2009 were \$(1.797) billion and \$(1.846) billion, respectively. In January 2009, the Company received \$1 billion, plus accrued interest, in full satisfaction of the 14% Senior Notes from Constellation Energy. In July 2009, the Company purchased 225 million shares, representing approximately a 10% interest, of BYD Company Limited common stock for \$232 million. Capital expenditures decreased \$730 million. Additionally, the Company received proceeds from the sale of certain Australian hydrocarbon exploration and development assets during the second quarter of 2010 totaling \$78 million and net proceeds from the sale of CE Gas (Australia) Limited during the third quarter of 2010 totaling \$59 million, partially offset by higher investments in companies accounted for under the equity method.

Capital Expenditures

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

	<u>2010</u>	<u>2009</u>
Capital expenditures⁽¹⁾:		
PacifiCorp	\$ 1,250	\$ 1,766
MidAmerican Funding	183	348
Northern Natural Gas	87	140
Kern River	85	37
CE Electric UK	254	297
Other	3	4
Total capital expenditures	<u>\$ 1,862</u>	<u>\$ 2,592</u>

(1) Excludes amounts for non-cash equity AFUDC.

The Company's capital expenditures relate primarily to PacifiCorp and MidAmerican Energy (the "Utilities"), which consisted mainly of the following for the nine-month periods ended September 30:

2010:

- Transmission system investments totaling \$322 million, including construction costs for the first major segment of the Energy Gateway Transmission Expansion Program, a 135-mile, double circuit, 345-kilovolt transmission line being built between the Populus substation in southern Idaho and the Terminal substation near Salt Lake City, Utah, the final section of which is expected to be substantially complete in the fourth quarter of 2010.
- Emissions control equipment totaling \$304 million.
- The development and construction of wind-powered generating facilities totaling \$145 million.
- Distribution, generation, mining and other infrastructure needed to serve existing and expected demand totaling \$662 million.

2009:

- Transmission system investments totaling \$573 million, including construction costs for the Populus-to-Terminal segment of the Energy Gateway Transmission Expansion Program at PacifiCorp.
- The development and construction of wind-powered generating facilities totaling \$391 million.
- Emissions control equipment totaling \$246 million.
- Distribution, generation, mining and other infrastructure needed to serve existing and expected demand totaling \$904 million.

Additionally, capital expenditures for the nine-month period ended September 30, 2010 include costs related to Kern River's two expansion projects totaling \$66 million. Kern River's 2010 Expansion project was placed in service in April 2010. 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, 2010 were \$(190) million. Uses of cash totaled \$563 million and consisted mainly of \$259 million for repayments of MEHC subordinated debt, \$142 million for repayments of subsidiary debt, \$87 million for net repayments of subsidiary short-term debt and \$56 million for net purchases of common stock. Sources of cash totaled \$373 million and consisted of proceeds from subsidiary debt totaling \$231 million and net proceeds from the MEHC revolving credit facility totaling \$142 million.

Net cash flows from financing activities for the nine-month period ended September 30, 2009 were \$(676) million. Uses of cash totaled \$1.918 billion and consisted mainly of \$667 million for repayments of MEHC subordinated debt, \$506 million for net repayments of subsidiary short-term debt, \$383 million for repayments of subsidiary debt, \$216 million for net repayments of the MEHC revolving credit facility and \$123 million for net purchases of common stock. Sources of cash totaled \$1.242 billion and consisted of proceeds from the issuance of subsidiary debt totaling \$992 million and proceeds from the issuance of MEHC senior debt totaling \$250 million.

Long-term Debt

In July 2010, MEHC called and repaid at par value \$92 million of 6.25% CalEnergy Capital Trust II subordinated debt due in February 2012.

In July 2010, Yorkshire Electricity closed on a £151 million finance contract with the EIB and issued £151 million of 4.13% notes due July 20, 2022. The net proceeds are being used to fund capital expenditures. Also in July 2010, Northern Electric closed on a £119 million finance contract with the EIB. Amounts available under the finance contract may be drawn upon through 2011.

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 rating, investors' judgment of risk and conditions in the overall capital market, including the condition of the utility industry in general. Additionally, the Berkshire Equity Commitment 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. In March 2010, MEHC and Berkshire Hathaway amended the Berkshire Equity Commitment extending the term from February 28, 2011 to February 28, 2014 and reducing the Maximum Equity Amount, as defined in the agreement, from \$3.5 billion to \$2.0 billion effective March 1, 2011.

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; 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 exclude non-cash equity AFUDC, are approximately \$2.7 billion for 2010, and include the following:

- \$459 million for transmission system investments at PacifiCorp, including \$206 million for the Energy Gateway Transmission Expansion Program, which includes costs for completion of the first major segment of the program, the Populus to Terminal transmission line.
- \$358 million for environmental projects at the Utilities to install and upgrade emissions control equipment at certain coal-fired generating facilities to meet anticipated air quality and visibility targets through reductions of sulfur dioxide, nitrogen oxide ("NO_x") and particulate matter emissions.
- \$155 million for construction and development of wind-powered generating facilities at PacifiCorp.
- \$138 million at Kern River for two expansion projects.
- Remaining amounts are for ongoing investments in distribution, generation, mining and other infrastructure needed to serve existing and expected demand.

MidAmerican Energy continues to evaluate additional cost-effective wind-powered generation. In December 2009, the Iowa Utilities Board ("IUB") issued an Order approving, subject to conditions, a settlement agreement between MidAmerican Energy and the Iowa Office of Consumer Advocate in conjunction with MidAmerican Energy's ratemaking principles application to construct up to 1,001 megawatts ("MW") (nominal ratings) of additional wind-powered generation in Iowa through 2012, the last 251 MW of which is subject to IUB confirmation. MidAmerican Energy has further committed that not greater than 500 MW will be placed in service during 2012. Wind-powered generation projects under this agreement are authorized to earn a 12.2% return on equity in any future Iowa rate proceeding. The Order has been appealed to the district court in Polk County, Iowa, by one of the intervenors in the proceeding.

Additionally, 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 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.

Contractual Obligations

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, 2009, other than the 2010 debt issuances previously discussed. 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, 2009, 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 energy cost adjustment mechanism ("ECAM") with the Utah Public Service Commission ("UPSC"). The filing recommends that the UPSC adopt the ECAM to recover the difference between base net power costs set in the next Utah general rate case and actual net power costs. The UPSC has separated the application into two phases to first address whether the mechanism is in the public interest, and then if it is found to be in the public interest, to determine the type of mechanism that should be implemented. The UPSC completed the phase one hearings in January 2010. In February 2010, the UPSC issued an order to proceed to the second phase, concluding that the public interest determination is dependent on evidence to be provided in phase two. Additionally, 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 seeking approval to defer incremental renewable energy credit revenue in excess of the renewable energy credit 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 renewable energy credit 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 November 2010, a final hearing on the ECAM was held with the UPSC. A final decision as to whether all or any of the net power costs and renewable energy credit revenues in excess of the levels currently included in rates will be collected from or passed through to customers is under consideration by the UPSC.

In February 2010, PacifiCorp filed an application with the UPSC requesting an increase of \$34 million associated with two major construction projects that were completed and in service by June 2010. The application requests recovery in conjunction with a future rate change. In March 2010, PacifiCorp updated its application to reflect the cost of capital decisions from the February 2010 general rate case order, reducing the amount requested for recovery to \$33 million. In May 2010, a multi-party stipulation was filed with the UPSC agreeing to recovery of \$31 million. In June 2010, the stipulation was approved by the UPSC.

In August 2010, PacifiCorp filed an application with the UPSC requesting an increase of \$39 million associated with two major construction projects expected to be complete and in service by December 2010. The application requests a 5% increase in rates effective January 2011 encompassing both the \$39 million requested increase and the \$31 million increase approved by the UPSC in June 2010. Collection of a one-time \$16 million surcharge for the portion of the \$31 million increase related to the period from July 2010 to December 2010 is expected to begin effective January 1, 2011.

Oregon

In February 2010, PacifiCorp made its initial filing for the annual transition adjustment mechanism with the Oregon Public Utility Commission ("OPUC") for an annual increase of \$69 million to recover the anticipated net power costs forecasted for calendar year 2011. In July 2010, an all-party stipulation was filed with the OPUC agreeing to an increase of \$58 million, or an average price increase of 6%. The OPUC approved the all-party stipulation in September 2010, subject to updates for anticipated net power costs through November 2010. In July 2010, PacifiCorp filed the first of three net power cost updates, requesting a revised increase of \$61 million. The final rates will be effective January 1, 2011.

In March 2010, PacifiCorp filed a general rate case with the OPUC requesting an increase of \$131 million, or an average price increase of 13%. In July 2010, a multi-party stipulation was filed with the OPUC agreeing to an annual increase of \$85 million, or an average price increase of 8%. If approved by the OPUC, the rates will be effective January 1, 2011.

Wyoming

In October 2009, PacifiCorp filed a general rate case with the Wyoming Public Service Commission ("WPSC") requesting a rate increase of \$71 million with an effective date of August 1, 2010. Power costs were included in the general rate case, reflecting increased coal costs and the expiration of low cost long-term power purchase contracts. The application was based on a test period ending December 31, 2010. In March 2010, a multi-party stipulation was filed with the WPSC agreeing to an overall rate increase of \$36 million, or an average price increase of 7%, to be implemented in two phases. In May 2010, the WPSC approved the settlement agreement. The first phase of the rate increase, consisting of a \$26 million increase, became effective July 1, 2010 and the second phase, consisting of the remaining \$10 million increase, will be effective February 1, 2011.

In January 2010, PacifiCorp filed its annual power cost adjustment mechanism ("PCAM") application with the WPSC requesting recovery of \$8 million in deferred net power costs. In March 2010, a multi-party stipulation was filed with the WPSC agreeing to reduce the requested recovery to \$4 million. In May 2010, the WPSC approved the settlement agreement allowing for the change in the PCAM surcharge rate effective April 1, 2010.

In April 2010, PacifiCorp filed an application with the WPSC requesting approval of a new ECAM to replace the existing PCAM. The PCAM will sunset with the final deferral of net power costs in November 2010 and collection through March 2012. In November 2010, the WPSC approved effective December 1, 2010, the deferral of net power costs incurred above or below base net power costs currently provided for in rates until the WPSC issues an order on PacifiCorp's application for the ECAM.

Washington

In May 2010, PacifiCorp filed a general rate case with the Washington Utilities and Transportation Commission ("WUTC") requesting an annual increase of \$57 million, or an average price increase of 21%. If approved by the WUTC, the rates will be effective in April 2011.

Idaho

In February 2010, PacifiCorp filed an ECAM application with the Idaho Public Utilities Commission ("IPUC") requesting recovery of \$2 million in deferred net power costs. In March 2010, the IPUC issued an order approving PacifiCorp's ECAM application effective April 1, 2010.

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%. If approved by the IPUC, the rates will be effective by January 1, 2011.

In June 2010, the IPUC approved an increase to PacifiCorp's energy efficiency rider to fund DSM programs of \$1 million, or an average price increase of 1%, with an effective date of July 1, 2010. As a result of the 1% increase, the energy efficiency rider in Idaho is now 5%.

California

In November 2009, PacifiCorp filed a general rate case with the California Public Utilities Commission ("CPUC") requesting an annual increase of \$8 million, or an average price increase of 10%. In June 2010, PacifiCorp filed with the CPUC an all-party joint motion for commission approval and adoption of the settlement agreement. The agreement reflects an annual increase of \$4 million, or an average price increase of 5%, and includes the establishment of revised depreciation rates on California distribution assets. In September 2010, the CPUC approved the settlement agreement with an effective date of January 1, 2011.

In August 2010, PacifiCorp filed an application with the CPUC to increase rates pursuant to the energy cost adjustment clause. In the application, PacifiCorp requested a rate increase of \$9 million, or an average price increase of 11%. If approved by the CPUC, the rates will be effective January 1, 2011.

Northern Natural Gas

In November 2009, the FERC issued an order initiating a rate proceeding under Section 5 of the Natural Gas Act for the purpose of investigating whether Northern Natural Gas' regulated rates are just and reasonable. In February 2010, Northern Natural Gas filed a cost and revenue study pursuant to the FERC's order that demonstrated no adjustment to Northern Natural Gas' regulated rates was warranted. In May 2010, a group of seven large customers filed a motion to terminate the proceeding provided Northern Natural Gas would not file to make new regulated rates effective prior to November 2011. The motion was supported or not opposed by customers representing 96% of the entitlement on Northern Natural Gas' system, as well as four state regulatory commissions and a consumer advocate intervenor. In May 2010, the FERC granted the motion to terminate the proceeding. Certain intervenors requested that the FERC rehear its granting of the motion. The FERC denied rehearing of the order in October 2010; however, the intervenors may appeal the decision by the end of December 2010. The Company does not expect the proceeding to have a material adverse effect on the Company's 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, climate change, 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 United States Environmental Protection Agency ("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, 2009.

National Ambient Air Quality Standards

In June 2010, the EPA finalized a new national ambient air quality standard for sulfur dioxide ("SO₂"). Under the new rule, the existing 24-hour and annual standards for SO₂, which were 140 parts per billion measured over 24 hours and 30 parts per billion measured over an entire year, were replaced with a new one-hour standard of 75 parts per billion. The new rule will utilize a 3-year average to determine attainment. The rule will utilize source modeling, in addition to the installation of ambient monitors where SO₂ emissions impact populated areas, with new monitors required to be in-service no later than January 2013. Attainment designations are due by June 2012, with State Implementation Plans due by 2014 and final attainment demonstrations by August 2017.

Under the new standard, the number of counties designated as nonattainment areas is likely to increase. Businesses operating in newly designated nonattainment counties could face increased regulation and costs to monitor or reduce emissions. For instance, existing major emissions sources may have to install reasonably available control technologies to achieve certain reductions in emissions and undertake additional monitoring, recordkeeping and reporting. The construction or modification of facilities that are sources of emissions could become more difficult in nonattainment areas. Until additional monitoring and modeling is conducted, the impacts on the Company cannot be determined.

Clean Air Transport Rule

In July 2010, the EPA proposed the Clean Air Transport Rule ("Transport Rule"), a replacement of the Clean Air Interstate Rule ("CAIR"), which requires electric generating units in 31 states and the District of Columbia to reduce emissions of SO₂ and NO_x on a state-by-state basis in accordance with each state's modeled contribution to nonattainment of the fine particulate standards in downwind states. The emission reductions required under the Transport Rule are intended only to resolve transported emissions and not to resolve air quality issues in the states where the generation is located. The Transport Rule's emission reduction requirements are proposed to take place in two phases, with the first phase beginning in 2012 and the second phase beginning in 2014. By 2014, the rule and other state and EPA actions would reduce power plant SO₂ emissions by 71% and NO_x emissions by 52% from 2005 levels in covered states. The EPA will administer separate trading programs for SO₂ and NO_x under the Transport Rule and has identified three potential options for implementation. The EPA's preferred approach allows limited trading of SO₂ allowances and region-wide trading of annual NO_x allowances. The second approach would allow trading of emission allowances only between facilities within a state. The final approach would not allow any trading of allowances. Under this approach each emitting facility would be required to meet plant-specific emission rates. Facilities are required to comply with the CAIR until the Transport Rule is in effect. Until the final Transport Rule is adopted, the impacts on MidAmerican Energy and CalEnergy U.S.'s natural gas generating facilities in Texas, Illinois and New York cannot be determined. The EPA anticipates finalizing the Transport Rule in 2011. PacifiCorp's generating facilities are not subject to the CAIR or the Transport Rule. It is possible that the existing CAIR or the proposed Transport Rule may be replaced with more stringent requirements to reduce SO₂ and NO_x emissions and that these requirements could be extended to the western United States through regulation or legislation such as a multi-pollutant emission reduction bill.

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 coal combustion storage and disposal. 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 Resource Conservation and Recovery Act ("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 6 landfills that contain coal combustion byproducts. MidAmerican Energy operates 8 surface impoundments and 4 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. Public comments on the proposed rule are due in November 2010. The impact of the proposed regulations on coal combustion byproducts cannot be determined at this time.

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 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, 2010, 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, 2010, the Company would have been required to post \$602 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 (the "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, will be 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." 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, 2009. There have been no significant changes in the Company's assumptions regarding critical accounting estimates since December 31, 2009.

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, 2009. The Company's exposure to market risk and its management of such risk has not changed materially since December 31, 2009. 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, 2010.

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 SEC'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, 2010 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

For a description of certain legal proceedings affecting the Company, refer to Item 3 of the Company's Annual Report on Form 10-K for the year ended December 31, 2009. Refer to Note 12 of Notes to Consolidated Financial Statements in Part I, Item 1 of this Form 10-Q for material developments since those disclosed in Item 3 of the Company's Annual Report on Form 10-K for the year ended December 31, 2009.

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, 2009.

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 Federal Mine Safety and Health Administration ("MSHA") under the Federal Mine Safety and Health Act of 1977 ("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 three-month period ended September 30, 2010. Closed or idled mines have been excluded from the table below as no citations, orders or notices were issued for such mines during the three-month period ended September 30, 2010. In addition, there were no fatalities at PacifiCorp's coal mines or coal processing facilities during the three-month period ended September 30, 2010.

Coal Mine or Coal Processing Facility	Mine Safety Act						Total Value of Proposed MSHA Assessments (in thousands)	Legal Actions Pending
	Section 104(a) 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		
Deer Creek	10	—	1	—	—	—	\$ 40	15
Bridger (surface)	2	—	—	—	—	—	4	6
Bridger (underground)	9	—	—	—	1	—	42	17
Cottonwood Preparatory Plant	—	—	—	—	—	—	—	—
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 5, 2010

/s/ Patrick J. Goodman

Patrick J. Goodman

Senior Vice President and Chief Financial Officer

(principal financial and accounting officer)

EXHIBIT INDEX

<u>Exhibit No.</u>	<u>Description</u>
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.

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, 2010 and 2009, as indicated in our report dated November 5, 2010; 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, 2010, 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 5, 2010

**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 5, 2010

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

**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 5, 2010

/s/ Patrick J. Goodman

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

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

I, Gregory E. Abel, 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, 2010 (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 5, 2010

/s/ Gregory E. Abel

Gregory E. Abel

President and Chief Executive Officer
(principal executive officer)

**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, 2010 (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 5, 2010

/s/ Patrick J. Goodman

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